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Technical and Economic Assessment of Potential to Upgrade Gob Gas to Pipeline Quality

COALBED METHANE OUTREACH PROGRAM

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Coalbed Methane Outreach Program
Atmospheric Pollution Prevention Division
U.S. Environmental Protection Agency

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MEASURES AND ACRONYMS

MEASURES:

Btu	British thermal units
F	Fahrenheit, degrees
hp	Horsepower
hr	Hour
mmBtu	Million British thermal units
mmscfd	Million standard cubic feet per day
mscfd	Thousand standard cubic feet per day
ppm	Parts per million
psi	Pounds per square inch
psia	Pounds per square inch, absolute
psig	Pounds per square inch, gauge
ppmv	Parts per million (by volume)
scf	Standard cubic feet

ACRONYMS:

AED	Alternative Energy Development, Inc.
AET	Advanced Extraction Technologies, Inc.
BACT	Best Available Control Technology
CMOP	Coalbed Methane Outreach Program
CRF	Capital Recovery Factor
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
GRI	Gas Research Institute
GWP	Global Warming Potential
NRU	Nitrogen Rejection Unit
PSA	Pressure Swing Adsorption
REI	Resource Enterprises, Inc.
U of U	University of Utah

1.0 INTRODUCTION AND BACKGROUND

Coal mines venting methane to the atmosphere are responsible for approximately eight percent of global methane emissions (EPA, 1993). Methane, in turn, is 21 times as effective as carbon dioxide in trapping heat in the atmosphere and accounts for 20 percent of the greenhouse effect that is causing global climate change. Much of the methane emissions from active coal mines comes from mine ventilation exhaust shafts, but the methane concentration is so minute (less than one percent) that it is rarely economically recoverable given current technologies. Gas from gob wells, the other major source at many active longwall mining operations, however, is available at methane concentrations from about 30 percent to over 90 percent. In this range of concentrations gob gas may become a valuable fuel for such uses as generating power in gas turbines or internal combustion engines, or for direct firing in industrial furnaces or boilers. Another potential use that seems well within reach is injection into natural gas pipelines after refinement to required gas quality specifications (typically to 97 percent methane by volume).

Because of a high level of interest among coal mine owners and others interested in refining (enriching) gob gas, the U.S. Department of Energy's Morgantown Energy Technology Center (DOE) sponsored and partially funded a study entitled "Commercialization of Waste Gob Gas and Methane Produced in Conjunction with Coal Mining Operations" (referred to as the DOE Report in this assessment). Resource Enterprises, Incorporated (REI), who co-funded the study, had a team which included the University of Utah (U of U) and Heredy Consultants. The study incorporated both original assessments of the subject and findings from previous studies, notably papers published by the Gas Research Institute (GRI). DOE published the final report from this research effort in 1993. It covered both the potential for conversion of gob gas to useful chemicals and enrichment to pipeline quality. The major conclusions of the report included the following:

- With technology that is already available, it is relatively straightforward to enrich a gas stream that contains only one contaminant. Gob gas, however, has four contaminants (nitrogen, oxygen, carbon dioxide, and water vapor) each of which may be separated from the methane using a combination of existing processes of varying degrees of complexity and compatibility. Designers of integrated clean-up processes therefore must use care to achieve operating and cost effectiveness as well as safety in a combined, or integrated, system.

- The nitrogen rejection unit (NRU) is the most critical and expensive component of any enrichment system. Three NRU technologies are potentially suitable: 1) cryogenics, 2) selective absorption, and 3) pressure swing adsorption (PSA). The cryogenics process is very sensitive to the presence of impurities and, therefore, may not be appropriate for a gob gas application (unless an improved system design is able to overcome such limitations). Both selective absorption and PSA are acceptable. Methane recoveries in both processes are similar and capital and operating costs are comparable. The selective absorption and PSA processes, however, handle oxygen differently. The selective absorption system requires oxygen removal prior to nitrogen rejection, whereas PSA removes most of the oxygen in the NRU. Thus an integrated process involving PSA would be less complex. The design of a PSA system must include safeguards to ensure that methane/oxygen mixtures passing through the explosive range are handled properly.

Since the publication of the DOE Report, technical advances claimed by system vendors have generated interest with mine operators wanting to sell their gob gas to natural gas pipelines.

These mine operators require an unbiased assessment of the potential to undertake enrichment projects based on proven technologies at their mines.

The purpose of this report is to reopen the 1993 review of integrated gob gas enrichment technology to determine which, if any, systems on the market are ready for implementation at mine sites at reasonable costs. This updated review examines average costs that projects would incur in a typical mine setting for a variety of feed gas qualities and daily flows. It also begins the process of evaluating promising technologies that have not yet been proven in commercial field trials.

This review found evidence that gob gas enrichment has made progress during the past three years. Suppliers of all three nitrogen rejection technologies affirm that a gob gas enrichment plant is technically feasible and free of unacceptable risks. Most suppliers are ready to make firm proposals for integrated enrichment plants. Although there is still no commercially available integrated facility enriching gob gas, mine operators and system suppliers are working on specific project applications, and there may soon be an operating plant. Full implementation is not yet a reality because nitrogen rejection techniques are still quite new, and mine operators have become interested only recently in using the methane in gob gas. Most of the cost evaluations for this report were performed in 1995. Since that time, Shirley, et al (1997) reported on a demonstration of a nitrogen rejection operation from gob gas. This report cites findings from this demonstration.

Another delaying factor in commercialization of gob gas enrichment has been the price of natural gas. At today's low gas prices, costs of upgrade plants may be favorable for gas sources above 5 mmscfd with methane contents at 80 percent or above. Smaller plants with lower percentages of methane tend not to be cost-effective, but economic results are quite site-specific. This report analyzed a range of cases using two very simple models. The analytical software used in this report is available from the EPA's Coalbed Methane Outreach Program (CMOP) (see Appendix F for contact information). Mine operators can use the models to assess whether gas enrichment would be cost-effective in their own economic situations and whether such projects could generate sufficient cash flow to attract capital investment.

Section 2 of this report presents a technical evaluation of available gob gas enrichment technologies. Section 3 discusses capital and operating costs for enriching gob gas sources over a range of flow rates and methane contents and presents three hypothetical project cash flow analyses that demonstrate favorable returns on investment. Section 4 summarizes the report's conclusions. Finally, the appendices contain cost analysis details, references, contact information, and a research report on a technical evaluation of gob gas enrichment performed by the Chemical and Fuels Engineering Department at the University of Utah.

2.0 EVALUATION OF GOB GAS ENRICHMENT TECHNOLOGIES

Gob gas compositions vary widely from mine to mine, well to well, and over time. Gob gas containing as little as 50 percent methane is at the low end of the range in which upgrading could be economically practical; while gas containing over 90 percent methane requires much less cleanup and is more valuable. From a practical standpoint, most gob gas enrichment projects will have feed gas compositions in the ranges shown in Table 1, taken from the DOE Report. Typical pipeline requirements for enriched, or “sales gas,” shown in the table are representative of specifications that vary from one pipeline company to another. It is the function of the enrichment plant to convert gob gas to a consistent product that meets pipeline specifications. If the plant operator were to encounter a pipeline that would accept more lenient specifications, the effect on the plant’s capital cost may be significant.

Constituent	Gob Gas (Range)	Pipeline Specification (Typical)
Oxygen	3 percent (2-6)	10 ppm
Nitrogen	16 percent (9-26)	3 percent max.
Carbon Dioxide	3 percent (3-9)	3 percent max.
Methane	78 percent (65-85)	97 percent
Water Vapor	Saturated	7 lbs/mmscf

Table 1: Typical Gob Gas Composition on a Volume Basis and Required Pipeline Composition (DOE, 1993)

Coal mine operators have three other options, besides enrichment, to bring their gob gas up to pipeline quality. First, they may invest in techniques designed to improve recovery so that the gob gas maintains the highest possible quality standard. Techniques include engineering designs that optimize gob well and borehole configurations and installation of monitoring systems. The enrichment step would probably come next and could be followed by blending with high quality methane if available. A final option is spiking with higher hydrocarbon gases such as propane (if allowed by the receiving pipeline). Blending and spiking may be most useful when operators encounter gob gas flows that consistently contain 90 percent methane or higher.

EPA prepared a user-friendly computer program that helps gas project developers to identify cost-effective combinations of the various upgrade options. Copies of the program, which are available from CMOP, allow the user to input case specific operating and market parameters. The program displays the approximate unit cost of optimum and alternate configurations. Those who wish more information on these techniques or want to obtain a copy of the model can contact CMOP (see Appendix F).

2.1 Integrated Approach

An integrated approach simply refers to an enrichment plant that removes all gas contaminants with a series of connected processes at one location. It is possible to design various integrated approaches for gob gas enrichment, but several design challenges confront system suppliers. Pipeline customers require that sales gas contain no more than three percent non-hydrocarbons by volume, and their oxygen requirements are especially stringent. Two gob gas impurities, carbon dioxide and water vapor, are easily removed to pipeline specifications using existing commercial technologies. Since nitrogen removal from methane is the most difficult separation technically, and the most expensive, an effective nitrogen rejection process will be critical for any integrated clean-up system. Technologies for nitrogen rejection as a single contaminant, at this scale, are commercially available and employed. But the presence of oxygen in the gob gas complicates some of the nitrogen rejection technologies. The final challenge is to effectively address the compositional and flow rate variability of gob gas. Results of the recent demonstration project (Shirley, et al, 1997), emphasize this very aspect and appear later in this report.

The 1993 DOE report described three available nitrogen rejection techniques (i.e. cryogenics, pressure swing adsorption, and selective absorption) and the status of system supplier efforts to adapt them to gob gas. Investigators for this (current) report re-contacted all firms that supplied information for the earlier report and contacted (known) new suppliers that are also developing nitrogen rejection systems. The research did not uncover any new suppliers that are ready to sell and guarantee full-scale nitrogen rejection systems. Some of the interviews covered a few small firms that are in the process of bringing systems to the market but that are in need of more development work. Information on these firms appears in Section 2.8 - Emerging Technologies, below.

During the writing of this report, U of U researchers found potential anomalies in some vendor approaches to integrated plant design. At that point, U of U undertook a technical assessment of each of the three technologies to determine if gob gas enrichment is feasible operating under field conditions. The assessment involved computer simulations of material and energy balances for various gas flow rates and qualities in each system. Section 2.7 contains summary results of that work. Detailed results of this study are presented in Appendix E. Sections 2.2, 2.3, 2.4, and 2.5 are descriptions and commercial summaries of the three NRU technologies and a summary of their differences. Section 2.6 discusses process components that may remove the three other contaminants: oxygen, carbon dioxide, and water.

Technical and cost information for the evaluations came from records previously gathered by U of U for DOE and other work from Gas Research Institute (GRI) reports and from potential suppliers through telephone and fax communications.

2.2 Cryogenics Process

The cryogenics process uses a series of heat exchangers to liquefy the high pressure feed gas stream. The process then flashes the mixture. A nitrogen-rich stream vents from a distillation separator, leaving the methane-rich stream. The cryogenics process recovers about 98 percent of the methane, the highest rate of the three nitrogen rejection alternatives evaluated. Large-scale cryogenic plants have become a standard and very reliable method of rejecting nitrogen from large gas streams. Two small engineering companies in Houston, TX have offered small-scale cryogenic nitrogen rejection plants (i.e. with inlet flow rates in the range of 2-10 million standard cubic feet per day). They are Darnell Engineering[1] and Schedule A (see contact information in Appendix D). Designs from these two companies differ only in minor

[1] The information used for Darnell Engineering in this report is over two years old. EPA was not able to reach them for further comment.

respects. Each has built systems that operate successfully in the field on substandard natural gas where nitrogen is the only contaminant that is in need of removal. They often upgrade gas with methane content as low as 30 percent. Another company, BCCK Engineering, Inc. in Midland, TX also offers a gob gas upgrade cryogenic system. BCCK participated in a small scale demonstration that yielded some positive results and is currently (December 1997) starting up a large scale plant.

Although the size of the gob gas market is at least two orders of magnitude smaller than their primary (low-grade natural gas) market, these firms indicate interest in it because they feel the cryogenics NRU is well suited to gob gas. The process may accommodate wide quality fluctuations and, because of an excellent turndown ratio, may handle changes in mass flow as well.

Interviews conducted for this report indicated that most of the oxygen removal may be accomplished in the cryogenic NRU itself, and it may not be necessary to employ a separate deoxygenation step. In response to the DOE Report's caution that even small amounts of oxygen in the feed gas would disable a cryogenic process, one of the suppliers showed little concern because that firm processed gasses containing some oxygen without first passing them through deoxygenation. U of U simulations (Appendix E), however, found that it may not be possible to remove oxygen as effectively. Flammability may also be of concern if oxygen is not removed up front. In any case, the supplier would prefer to conduct gob gas field trials initially where there is little or no oxygen in the feed. These companies feel confident that there are no problems enriching gob gas with cryogenics (e.g. safety concerns or the presence of contaminants) that cannot be overcome with proper design. In fact, BCCK is demonstrating its confidence by going forward with the full scale gob gas enrichment project currently undergoing startup.

2.3 Pressure Swing Adsorption (PSA)

In most PSA NRU systems, wide-pore carbon molecular sieves selectively adsorb nitrogen and methane at different rates in an equilibrium condition. In the gob gas stream containing a mixture of nitrogen and methane, methane is preferentially adsorbed during each pressurization cycle. The process recycles methane-rich gas so that methane proportions increase with each cycle. PSA recovers up to 95 percent of available methane and may operate on a continuous basis with minimal on-site attention. PSA systems have excellent turndown capability so they are able to operate effectively with gas flowing at a fraction of rated capacity.

This study identified three firms that could offer a molecular sieve PSA system to enrich gob gas. Two of these, UOP from Houston, TX and Nitrotec Engineering based in Houston, TX, are presently offering commercial systems and supplied some engineering and cost information. BOC Group from Murray Hill, NJ recently discussed a PSA process demonstration at two different scales (Shirley, et al, 1997). This report provides some details of this paper. Gas Separation Technology in Colorado is developing another PSA process that is not yet commercially available (see Section 2.8). It is conceptually different from the other PSA processes as it uses naturally occurring zeolite instead of wide-pore carbon molecular sieves.

The UOP and Nitrotec PSA processes are similar except for some differences in the pressurization and evacuation steps and several other plant details. There are hundreds of PSA units operating in the field, only a few of which reject nitrogen, and those are employed in substandard natural gas fields where nitrogen is the sole contaminant. Because PSA plants may run with little on-site operator attention, monitoring from remote locations is especially practical. Technical details and cost estimates changed very little since 1993.

The two manufacturers currently offer to build commercial scale integrated gob gas enrichment facilities for interested mine owners without further research or field trials. Some gob gas projects may be cost-effective now, and many more will be if natural gas prices were to rise even slightly. They feel that PSA facilities will not present unusual risks because no change of phase takes place (e.g. gas to liquid, liquid to solid, etc.) and the process is very flexible with respect to changes in gas quality and flow rates. PSA suppliers see risk potential, not on the plant side, but on the "mine side" (i.e. the ability of the mine operator to maintain gob gas feed streams within practical limits without disrupting mine operations). They hope that mine operators are willing to consider the impact on their enrichment plants before changing gob well operating settings or taking wells on and off line.

Even with these assertions, an air rejection demonstration by BOC Gases (paper by Shirley, et al, 1997) encountered formidable difficulties in implementing a two-bed PSA process with feed gas compositional variations. The paper described the demonstration at two scales, a "demonstration" scale of 0.5 mscfd and "commercial" scale of 30-60 mscfd. BOC reported good methane recovery (98 percent of available feed). The high quality product requirement (~96 percent methane), however, necessitated feed rates lower than the nominal rating. At the higher operating rates, Shirley, et al observed difficulties in controlling the composition of the product gas. Operators paid considerable attention in the demonstration to limiting or eliminating explosion hazards.

PSA suppliers are generally ready to design and build integrated facilities and turn them over to customers once the facilities pass all performance tests. Assuming compliance with maintenance procedures, PSA suppliers will warrantee plant performance during its operation. At least one PSA gob gas enrichment plant is in the planning stage in Appalachia.

2.4 Selective Absorption

Sometimes referred to as Solvent Absorption, this process uses specific solvents that have different absorption capacities with respect to different gas species. The petroleum industry commonly uses selective absorption to enrich gas streams. One firm that offers selective absorption to reject nitrogen from methane is Advanced Extraction Technologies, Inc. (AET) of Houston, TX. Bend Research Inc. of Bend, OR also developed nitrogen-selective absorbents but does not offer a commercial scale plant (see Section 2.8).

AET demonstrated its nitrogen rejection technology with a 5 mmscfd unit installed at a substandard natural gas field in Hugoton, KS. The AET process uses a special hydrocarbon solvent that selectively absorbs methane while rejecting a nitrogen-rich stream in a refrigerated environment. The process will accept variability in feed gas flow rates and composition. The company expressed confidence that it can supply an integrated plant that will remove all four gob gas impurities. By removing the oxygen in the first step there will be no harmful effect on the solvent absorption unit. The company is ready to offer the system to interested mine owners. AET's primary marketing target for the unit is removing nitrogen in low-grade natural gas. Their interest lies in the much smaller gob gas market as well, however. Both markets would be more attractive if the natural gas price were to improve.

2.5 Summary of Nitrogen Rejection Process Characteristics

Table 2 lists some of the more basic characteristics and differences for the six NRU systems discussed above. The list is not complete; it only includes vendors that supplied technical and cost details of their systems.

	UOP	Nitrotec	BOC	AET	Darnell	Schedule A
NRU Technology	PSA	PSA	PSA	Selective Absorption	Cryogenic	Cryogenic
Phase Change	No	No	No	No	Liquefy	Liquefy
Methane Recovery	Up to 95%	Up to 95%	98%	96 to 98%	98%	98%
First Stage Deoxygenation	No	No	No	Yes	Yes	Yes
Offer Design, Build Integrated Gob Gas Plant	Yes	Yes	Yes, Possibly	Yes	Yes	Yes, after trials

Table 2: Summary of Nitrogen Rejection Enrichment Systems

2.6 Other Processes

Processes to remove the contaminants (oxygen, carbon dioxide, and water vapor) are commercially available from many established suppliers using a number of different techniques. The integrated enrichment plant supplier most probably will be an NRU vendor and would select and take overall responsibility for these other contaminant removal systems.

2.6.1 Oxygen Removal

For reasons explained earlier and in Section 2.7, deoxygenation will be the first process component in the plants with cryogenic or solvent absorption NRU's. It will be the last step with the PSA process, however, because the PSA plant will have removed most of the oxygen along with nitrogen in the NRU.

All gob gas enrichment plants will use catalytic deoxygenation. There are other deoxygenation techniques that are not as appropriate for this application. For example, using hydrogen to form water presents an unacceptable combustion risk at a plant site. The catalytic deoxygenation process is extremely exothermic, and every percentage increase in oxygen concentration increases the temperature by about 700^{o}F. The major concern is the upper temperature limit that a plant can tolerate. It is not practical to operate the process above 2000^{o}F, so a recycle mechanism would be necessary if inlet oxygen were to exceed 1.5 percent. It may be possible to use some of the heat for other parts of an integrated plant. Shirley, et al (1997) refer to a catalytic reduction with hydrogen, although the paper provides no details. Use of hydrogen will allow the removal of higher oxygen concentrations without recycling, and at lower temperatures. The presence of hydrogen on site, however, will require additional safety features.

There is also a possibility that the vent gas mixtures will reach the upper combustion limit for methane and air as they exit the unit. These concerns are topics during engineering optimization of the integrated process.

2.6.2 Carbon Dioxide Removal

Either amine units or membrane technology may be suitable carbon dioxide removal processes as both are well-established technologies. No one has observed the sensitivity of either process to other contaminants and flow variations associated with gob gas. An amine unit will tolerate only low levels of oxygen in the feed stream, so the amine unit must be downstream of the deoxygenation unit. Membrane processes may not be suitable to reduce carbon dioxide concentrations to below one percent. Another alternative for removing carbon dioxide, one that may offer cost advantages, is selective adsorption using a molecular sieve.

2.6.3 Water Vapor Removal

Dehydration of the gob gas is the simplest part of any integrated system design. Most system suppliers will employ a molecular sieve dehydration stage because of its proven record and economical operation.

2.6.4 Hydrogen Sulfide Removal

Hydrogen sulfide is the contaminant that gives “sour gas” its name. It is not as common as the four major gob gas contaminants (for example, it is not present in the Northern Appalachian Basin), but when it occurs, it must remain below the 4 ppmv level for acceptance by natural gas pipelines. The Gas Research Institute recently conducted field trials of several methods of hydrogen sulfide removal. A GRI article (Fisher, 1995) discusses process effectiveness, cost, and disposal issues.

2.7 Technical Assessment

The Department of Chemical and Fuels Engineering at U of U performed a technical assessment of the three NRU processes described in this report as the key components of their respective integrated gob gas enrichment facilities. U of U used CHEMCAD, a simulation package, to model the cryogenics and selective absorption process. Because PSA is a dynamic process, the researchers used different analytical methods for that process. Appendix E includes a copy of this report. The following is a summary of the principal findings:

2.7.1 Cryogenics Process

The cryogenic distillation process does not remove oxygen in the same proportion as nitrogen. In order to avoid an explosive condition in the waste gas stream, the deoxygenation unit must precede all other processes. Inlet oxygen concentration to the deoxygenation unit should remain below 1.5 percent in order to avoid high temperatures in the unit. Since most gob gases will have more than 1.5 percent oxygen, a recycle scheme is necessary and the deoxygenation unit’s flow capacity would need to be several times that of the main plant.

The process is technically feasible, but requires additional heat exchangers and process equipment. Controlling this integrated process to accommodate compositional and flow rate variations makes it the most complicated of the three NRU techniques.

2.7.2 Selective Absorption

Like the cryogenic process, deoxygenation must precede all other process steps for this technique, and the deoxygenation unit must be large enough to remove the largest anticipated concentration of oxygen (i.e. the oxygen content in the lowest quality feed gas that the unit can accept). Selective absorption will yield a high purity product. The NRU itself is very flexible and can accommodate compositional and flow variations.

Nitrogen and oxygen will separate from methane in the same proportion in a PSA NRU, making the final oxygen removal step simpler and not subject to a recycle configuration. If the process were designed for high methane recovery under ideal conditions, there would be a concern for flammability within the waste gas stream. The study established that high recoveries are theoretically achievable using practical pressure ratios, given the adsorption isotherm data. However, in multiple-bed PSA operations, recoveries will likely be lower and flammability risks will be lower. Because CHEMCAD cannot model the dynamic PSA process, the researchers could not assess the extent of reduced methane recovery under actual conditions. The range of recovery is approximately 80 to 95 percent (Shirley, et al [1997] report recoveries of about 98 percent). The lower end of that range will substantially impact product unit cost. Another way of expressing that impact is that total cost will remain constant, but revenue will decrease commensurately with reduced product recovery. PSA is a flexible process that may meet compositional and flow rate changes by varying pressure ratios and cycle times. Even though this is true in theory, Shirley, et al (1997) reported that product specifications could not be maintained in the wake of some feed gas compositional variations. Their demonstration makes it clear that building an integrated process to remove all contaminants at a mine with varying feed gas changes (flow rates and compositions) will not be a trivial exercise, even though individual contaminant removal processes are proven.

2.7.4 General

All of the three integrated processes are capable of functioning and yielding pipeline quality gas, although many uncertainties remain. Providing process control for any of the three is going to be a significant technical challenge in the presence of variations in the feed gas. In order to maintain strict specifications for the product gas, it may be necessary to blend varying amounts of a higher quality gas on an as-needed basis to maintain the feed within a permissible range. An operator may have pure blending methane available from virgin coal boreholes (an inexpensive option), from local natural gas distributors, or from recycling the enriched product gas itself. If it is not practical to take blending methane from these sources whenever they are needed, the operator may choose to install a pure methane surge system with enough storage capacity to keep the plant operating during short periods of off-quality feed gas. Either arrangement will allow the enrichment plant to adjust feed gas quality automatically, and it will improve the plant’s on-line time.

2.8 Emerging Technologies

This investigation identified other companies that are developing different nitrogen rejection technologies that are potentially applicable to an integrated gob gas cleanup system.

2.8.1 Alternative PSA Technologies

Gas Separation Technology of Golden, CO offers a PSA process that uses narrow pore zeolites as molecular sieves to effect separation. The company completed extensive laboratory tests of the process in which zeolite adsorbed nitrogen and oxygen preferentially over methane. Pressure drop and vacuum regenerate the zeolite and desorb the contaminants. The process operates at around 150 psig and recovers about 90 to 95 percent of the methane. The company reports that the process is capable of operating on gob gas containing as much as 75 percent air, and that they anticipate costs, for the NRU only, to be comparable to other PSA supplier costs. This technology has not operated at commercial scale or with all four gob gas contaminants.

One other company, Northwest Fuel Development, Inc. (NW Fuel) of Lake Oswego, OR is reporting (Soot, 1997) modified and improved PSA technology for nitrogen removal during tests at an abandoned mine in Ohio. The company developed new and improved selective adsorbents and optimized the cycle times to where the PSA essentially becomes a continuous process. The process has several limitations. It can reject only about 50 percent of the nitrogen from the feed. It retains about 70 percent of feed methane (while rejecting 30 percent), and the feed gas must contain 85 percent methane or better. The prospect of low costs, however, (NW Fuel estimates nitrogen rejection costs of $0.35 to $0.90 per mmBtu) may compensate for the limitations. The company is concentrating on smaller units (e.g. several hundred thousand cubic feet per day) which is a market niche that major suppliers have not entered. Since this process is in the development stage, it was not considered in the analyses.

2.8.2 An Alternative Absorption Technology

Bend Research Inc. of Bend, OR, developed a series of nitrogen-selective liquid absorbents based on transition metal complexes (as contrasted with AET's hydrocarbon solvents). The process uses pressure and temperature controls and regenerates the absorbent. Methane and other higher hydrocarbons pass through a standard packed column while nitrogen is selectively absorbed in the column. A pump then directs the liquid absorbent to a flash tank where the nitrogen desorbs, regenerating the absorbent. Absorbents under development exhibit tolerance to carbon dioxide, hydrogen sulfide, and low (ppm) levels of oxygen.

The company projects costs for an NRU that may be comparable to competing units in the 5 mmscfd size range, but it is not clear what contaminant levels they assumed for such estimates (Babcock, et al, 1997). There are no reports of field trials available.

2.9 Technical Assessment Summary

Even though the individual technologies for rejecting nitrogen, carbon dioxide, oxygen, and water may be considered "established," a system comprising all of the four processes working together on variable quality and flow, gob gas has not yet operated in commercial scale, although one may soon do so. Carbon dioxide and water removal techniques are very well established. Deoxygenation is less well established. Nitrogen rejection is not well established with respect to gob gas field conditions because it operates mostly on relatively rich natural gases not subject to extreme feed swings.

As nitrogen rejection is the most expensive of the four processes, NRU suppliers have been the proposers of new integrated gob gas upgrade systems. Some of these firms have less experience with removing oxygen and other contaminants, and they must use rigorous engineering during process design to be certain that the integrated systems will function reliably.

The technical assessment concluded that all three nitrogen rejection techniques could successfully operate as the principal component of an integrated plant to enrich gob gas. A cryogenics unit would be risky, however, given the presence of oxygen and carbon dioxide and the compositional and flow rate variations inherent with gob gas. In the selective absorption process, oxygen removal must be the first step. Systems that carry oxygen through the process units (such as PSA) would have to provide designs that remove the risk of explosion in certain combinations of oxygen and methane. Shirley, et al (1997) showed, for the PSA process, that this could be accomplished with careful engineering and design.

The interviews conducted for this assessment revealed that all three technologies reported by their respective suppliers were technically feasible and free of unacceptable risks when fed with gob gas, although no system supplier actually provided laboratory or field data to substantiate such assertions. The Shirley, et al (1997) air rejection demonstration data underscores this point. Removing all the impurities in an environment of varying feed gas composition and flow rate will be a formidable task. With the exception of two of the cryogenic firms, system suppliers are ready to make firm proposals to mine operators for integrated enrichment plants.

2.10 Outlook

There are two fundamental reasons why a gob gas enrichment facility is not in existence yet:

- *Nitrogen rejection is still an emerging and developing technique, and removal of four contaminants in one facility is, theoretically, feasible but unproven.* The question of technical feasibility comes down to one of proof. The industry that would supply the systems believes that gob gas enrichment technology is straightforward, feasible, and presents no unusual risks. On the other hand, the customer that would purchase the systems is not in a position to spend several million dollars for a system that cannot be seen and demonstrated. Gob gas enrichment is at the point of needing a commercial scale demonstration facility, underwritten by a system vendor, that will prove technical functioning of at least one of the systems offered and display any other benefits that would accrue to a mine operator, including an attractive return on investment (As of December 1997, BCCK is in the process of bringing an integrated gob gas enrichment facility on-line.).

- *Low natural gas prices.* Until late 1996 when natural gas prices started to move above two dollars per million Btu's, inexpensive natural gas had made it less likely for system suppliers and customers to jointly effect a full-scale demonstration of an integrated enrichment facility. The following section shows that the cost of upgrading gob gas is a major percentage of the current price that an operator would receive for this commodity in the marketplace.

On the other hand, there are indications that the conditions may soon become more supportive of gob gas enrichment. The technical assessment performed as part of this report removed many of the technical doubts on the three processes. Remaining challenges, such as design of suitable control systems and maintaining feed gas specifications, appear to require only sufficient engineering and field trials. Mine operators and developers have become more aware of gob gas use options (through the Coalbed Methane Outreach Program and other mine industry sources). They should be willing to investigate projects at their own mines once commercial demonstration of an enrichment plant becomes a reality. It is also reasonable to assume that some mine operators will invest in a facility because of the excellent return on investment that some project configurations will yield, as detailed in the next section.

3.0 COST ANALYSIS

3.1 Objective

The objective of the economic analysis portion of this report is to investigate the potential for economic deployment of gob gas enrichment systems over the following ranges of feed gas conditions:

Methane content - 30, 50, 60, 70, 85, and 90 percent
Gas flows - 2, 3, 4, 5, and 6 mmscfd

Early in the analysis it became clear that gob gas flows of less than 3 mmscfd and methane concentrations of less than 50 percent could not provide positive cash flow with natural gas prices at or somewhat above current levels. Therefore, the analysis includes flows of 3 mmscfd and methane contents of 50 percent and above.

3.2 Cost Summary

A summary of each analysis appears in Table 3 which expresses costs as dollars per million Btu for each of the three technologies. The sources of the data for Table 3 are Tables 1.1 through 1.20 in Appendix B. Each table covers a different feed gas case in terms of flow rate and methane content. The main part of the analysis described below entailed estimating capital and operating costs for each feed gas condition and comparing the total costs with revenues that might reasonably be expected by selling gas to natural gas transmission companies. The discussion includes methods for profitable plant siting and strategies for reducing plant costs.

The analysis determined that the costs of the three integrated technologies using the three different NRU approaches were not significantly different, given the uncertainties in the cost data. Costs of individual enrichment technologies depend on specific mine conditions, exact engineering designs, and cost agreements that mine operators can work out with individual vendors. The report lists the enrichment costs as both a "low-end" estimate and a "high-end" estimate. The error within each of these estimates is probably about 20 percent due to uncertainties in the cost data and also due to the fact that cost data on a commercially operating integrated plant are not available.

3.3 Plant Size Selection

When a potential operator plans the size of an enrichment facility there are several factors to consider. The *first* is how much gob gas will be available for the plant on an average day and how much variation will there be. *Second*, what is the average composition of the feed gas and how does it fluctuate. *Third*, what are the plant sizes in terms of inputs that are available. *Fourth*, how much of the feed gas would be consumed by the plant's compressors and other gas fueled machinery (this analysis assumed that the most economical energy source for the compressors would be the gob gas itself having undergone minimal cleaning or other treatment). *Fifth*, how much gas product (sales gas) would such a plant yield on a daily basis. And *sixth*, what percentage of the time would the plant actually run (i.e. availability or on-line percentage).

In selecting nominal case increments the team decided to use average daily flow of gob gas, because mine owners can most easily relate to that parameter (although getting an accurate projection of daily flow is not always possible).

Table/Inlet Gas Conditions	Low-end Estimate	High-end Estimate
TABLE 1.1 - 3 mmscfd, 50 percent	3.34	3.85
TABLE 1.2 - 3 mmscfd, 60 percent	2.54	2.97
TABLE 1.3 - 3 mmscfd, 70 percent	1.94	2.29
TABLE 1.4 - 3 mmscfd, 85 percent	1.55	1.66
TABLE 1.5 - 3 mmscfd, 90 percent	1.45	1.55
TABLE 1.6 - 4 mmscfd, 50 percent	2.95	3.45
TABLE 1.7 - 4 mmscfd, 60 percent	2.27	2.67
TABLE 1.8 - 4 mmscfd, 70 percent	1.76	2.08
TABLE 1.9 - 4 mmscfd, 85 percent	1.43	1.65
TABLE 1.10- 4 mmscfd, 90 percent	1.34	1.42
TABLE 1.11- 5 mmscfd, 50 percent	2.83	3.19
TABLE 1.12- 5 mmscfd, 60 percent	2.14	2.44
TABLE 1.13- 5 mmscfd, 70 percent	1.63	1.89
TABLE 1.14- 5 mmscfd, 85 percent	1.29	1.49
TABLE 1.15- 5 mmscfd, 90 percent	1.21	1.38
TABLE 1.16- 6 mmscfd, 50 percent	2.52	2.82
TABLE 1.17- 6 mmscfd, 60 percent	1.94	2.19
TABLE 1.18- 6 mmscfd, 70 percent	1.50	1.73
TABLE 1.19- 6 mmscfd, 85 percent	1.22	1.41
TABLE 1.20- 6 mmscfd, 90 percent	1.14	1.30

Table 3: Summary of the Low and High Gob Gas Enrichment Costs ($/mmBtu)

A mine that projects 3.0 mmscfd will only have about 2.65 mmscfd available (after subtracting compressor fuel), but is limited to the choice of a 3 mmscfd plant from most vendors. Obviously that plant will be under-employed on all but peak production days. As capital costs are many times as high as operating costs, load factors significantly below 85 or 90 percent may be very costly. Finally, sales gas quantities will vary greatly between systems for a given available flow increment because two other factors are at work: methane loss within the process, and expected reliability (on-line) percentage. Unless system suppliers find an easy way to customize plant size to each mine's gas profile, there will be certain awkward and costly matches (e.g. the 3 mmscfd case cited above). A much better case is a mine having 4 mmscfd available that purchases a 3 mmscfd unit. Only on low flow days will that plant be under-utilized, keeping unit capital costs low. A relatively small amount of gob gas flared or emitted will cause the only extra cost resulting from this case.

3.4 Cost Data and Engineering Estimates

The sources for capital and operating cost data are the 1993 DOE Report supplemented with data collected from vendors during the preparation of this report. Where prices were not readily available on certain items, the report assumes that similar components (e.g. removal units for oxygen, water vapor, or carbon dioxide, and compressors) would have similar capital costs so as not to skew one technology versus another. Costs for scaled-up units (except for compressors that are linearly proportional to the flow rate) increase according to the 0.6 rule.[2]

> *The reader should note that, with all the cost standardization, interpolation, and extrapolation, as well as time elapsed since the 1993 DOE Report, these cost estimates must be considered preliminary, particularly in light of the new air-rejection demonstration data published by Shirley, et al (1997).*

A more rigorous engineering analysis is necessary to narrow the cost uncertainties.

3.4.1 Compression Requirements

Gas compression requirements comprise a large percentage of capital costs. The report assumed that the feed gas is available at atmospheric pressure (14.7 psia) and that the sales gas pressure is 600 psia. That pressure may be too low for larger pipelines and too high where gas may be sold at distribution pressures. In any case, an interested mine operator may substitute the actual delivery pressure for the particular case before using these estimates. The analysis used the following standard engineering calculations and assumptions to build the estimates:

- Cryogenic Process: Inlet pressure for the cryogenic process is about 800 psi. During the DOE Report preparation, investigators assumed that process outlet pressures were close to atmospheric. However, Schedule A reported that it is between 80 and 190 psi, thus decreasing power requirements for the sales compressor. This analysis assumed an outlet pressure of 80 psi.

- PSA Process: Nitrotec's PSA is low-pressure separation (below 50 psi) while UOP's PSA operates at around 150 psi. The assumption in this report is that the pressure of the outlet streams in the PSA process is close to the inlet pressure. Analysts calculated compression requirements and compared them to compression charts supplied by the vendors. In some cases they had to defer to vendor numbers. The recycle compression requirements were more difficult to estimate. It is reasonable to assume a linear relationship for recycle compression requirements with respect to flow rate, and an inverse linear relationship with respect to methane content.

- Selective Absorption Process: Inlet pressure for AET's process is about 300 psi. Calculated feed and sales compression requirements were consistent with numbers provided by the company.

3.4.2 Methane Recovery

Methane recovery refers to the percentage of feed gas methane that exits the process as sales gas. The difference between the recovery percentage and 100 percent represents the methane lost during processing. Methane in gob gas used as fuel for process compressors (see 3.4.3 below) does not enter into this calculation. The analyses assumed recoveries of 90 percent for PSA processes and 96 percent for selective absorption and cryogenic processes.

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[2] The "0.6 Rule" approximates the cost of a larger or smaller piece of equipment by taking the ratio of the new size rating (e.g. flow capacity) to the original size and raising it to the 0.6 power. For example, Tractor B is twice as large as Tractor A, but it may cost just 1.52 as much as Tractor A.

3.4.3 Fuel Requirements

The most economical energy source for the compressors is the unprocessed gob gas which would be diverted from the enrichment processing system. The moisture content of the saturated gob gas decreases the quantity of methane available for powering the compressors. The analysis used adjusted heating values of 680 Btu/scf for the gas containing 70 percent methane and 825 Btu/scf for the gas containing 85 percent methane. Compressor fuel requirements are approximately 10,000 Btu/hr/hp, using a well established rule of thumb.

The cost assumptions included a very simple gas cleanup module for the compressor fuel to remove most of the particulates and moisture. Engine-driven units are more practical and less costly to run than electric units. It is not necessary (and much too expensive) to take partially processed feed gas from the enrichment plant and use it for compressor fuel. Dewpoint (condensation) problems remain under control by keeping the exhaust hot enough in the presence of acid gases. Sulfur dioxide is not a problem with gob gas combustion as there is little or no sulfur in the gas. Developers may have to file an extensive air permit application for the compressor engines. Engines must employ state-of-the-art, lean-burn technology to minimize the production of NO_x, which will be less than 35 tons per year for any of the plant configurations reported on in this report. The application will probably contain a BACT analysis proving that there is no better alternative commercially available.

3.4.4 Estimation of Error

All of the numbers used in this analysis will contain a certain amount of error -- as much as 20 percent or even up to 40 percent -- based on the technical and cost uncertainties raised in the new paper by Shirley, et al (1997). For each of the three technologies, the NRU is the largest component and, therefore, has the largest impact on plant cost estimates. NRU installed cost estimates cannot be accurate until project specific engineering details are available. The report tends toward conservative plant estimates by assuming purchase of new equipment (except for carbon dioxide removal units) and using a 10 percent contingency factor applied to the entire plant. These are probably good first order estimates of capital cost, but they cannot be relied on when making technology or supplier selection. A more sophisticated economic analysis would not be more useful at this stage because engineering analysis, optimization, and full-scale demonstration must take place first.

Similarly, the operating cost estimates appear to be conservatively high. The tables list one full-time operator for each plant even though some installations will run well automatically, with attention required from a fraction of one full time position. Assumed standard amounts for supervision and overheads are subject to reduction or elimination in certain cases.

Appendix A contains a discussion of how the analysis projected the remaining costs. Using these explanations a mine operator may substitute cost factors based on real physical and economic conditions in the area to arrive at a more realistic result.

3.5 Analysis Format

Appendix B presents two cost analysis formats:

- The first is Unit Cost Analysis comprising one sheet for each of the twenty selected inlet gas conditions in the ranges from 3 to 6 mmscfd and 50, 60, 70, 85, and 90 percent methane. Each of these analyses calculates a low-end and a high-end cost. Unit costs are the result of dividing total annual plant costs by the expected energy sales quantity. The purpose of this format is to provide a simple screening technique and to observe the effects of changing gas flows, plant size, and gas compositions. The major simplifying assumption in this analysis is the use of the capital recovery factor (CRF) representing a 10 year economic life and an internal rate of return requirement of 25 percent. The total capital costs use this CRF of 0.28 to arrive at an annual capital "cost." The 10 year CRF is a fair approximation of a range of project lives. For example, if a project were to last only eight years the CRF would be 0.30, and with a fifteen year life (as shown on the Cash Flow Statements discussed in the following paragraph) the CRF would drop slightly to 0.26. Table 3 contains the unit cost results of all twenty scenarios.

- The second format is a Cash Flow Statement (for selected scenarios only) that uses an income statement format with some cash flow adjustments and an internal rate of return calculation. The purpose of including cash flow statements is to depict typical business realities of a gob gas enrichment project including allowances for royalties, severance taxes, and ad valorem taxes. One element of the cash flow statement that can only come from interested mine operators is an allowance for state and federal taxes. Tax estimates do not appear because of the broad range of possible tax situations. Another assumption that simplified the analysis is that all capital for the project would be equity (i.e. no debt would be used to leverage the capital purchase). This is a conservative assumption, especially during periods of low interest rates. There are lines in the model, however, for quantifying effects of debt repayment on annual cash flow.

3.6 Analysis of Results

In spite of possible estimation errors and the lack of engineering standardization among the different proposed systems, it is quite possible to draw some conclusions from the cost and cash flow analyses appearing in this report. Charts of certain key relationships (see text below and Figures 1 through 4 on the following pages) use data from Table 3.

3.6.1 Cost Sensitivity to Gas Flow Rate

Figure 1 shows that low-end costs of the product gas decrease significantly as the size of the plant and available gob gas supplies increase. The chart does not show plant costs below 3 mmscfd because most vendors do not offer plants below that size, and the results would be uneconomical in many markets at today's price for natural gas. At the higher plant sizes, the unit gas costs appear quite promising, although it should be noted that these are low-end costs.

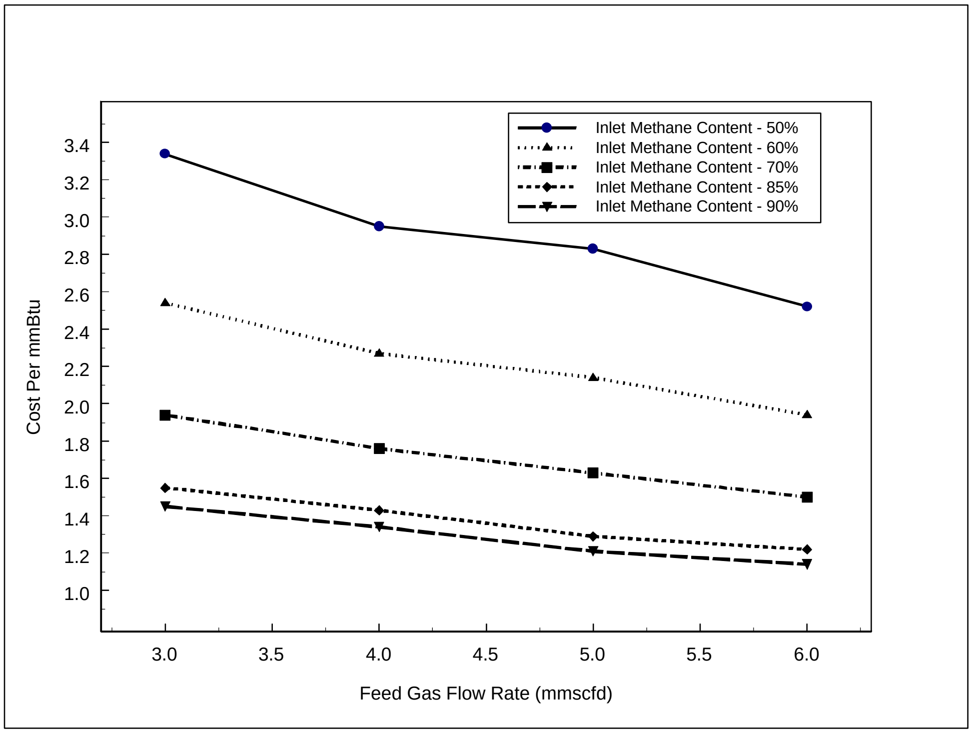

Figure 1: Low-end Costs versus Feed Gas Flow Rate

3.6.2 Cost Sensitivity to Methane Content of the Feed Gas

Figure 2 plots the unit cost of gas enrichment against the percentage of methane in the gob gas. While system suppliers indicate the ability to enrich feed gases with as little as 50 percent methane, they have had very little experience operating at this level. Unit process costs are very sensitive to decreasing feed gas quality because the product yield is decreasing while rejection costs keep rising. Enrichment may not be an affordable option with gob gas averaging much below the 70 percent methane level, unless natural gas prices were to increase substantially. A mine that wants to enrich lower quality gob gas may blend it with a high quality source, produced or purchased, to achieve an acceptable feed gas. While that means processing a quantity of already valuable gas, this strategy may be able to take advantage of the economy of scale of the larger plant needed to enrich the blend.

At the upper end of the feed gas quality range there is little cost advantage for each increment of methane content (e.g. it costs almost as much to enrich a 90 percent gas as an 85 percent gas). The project developer should investigate less expensive options for enriching 90 percent gas. Section 2.0 discusses removing only the oxygen and water vapor and then blending with pure methane or spiking with a high heat value fuel such as propane.

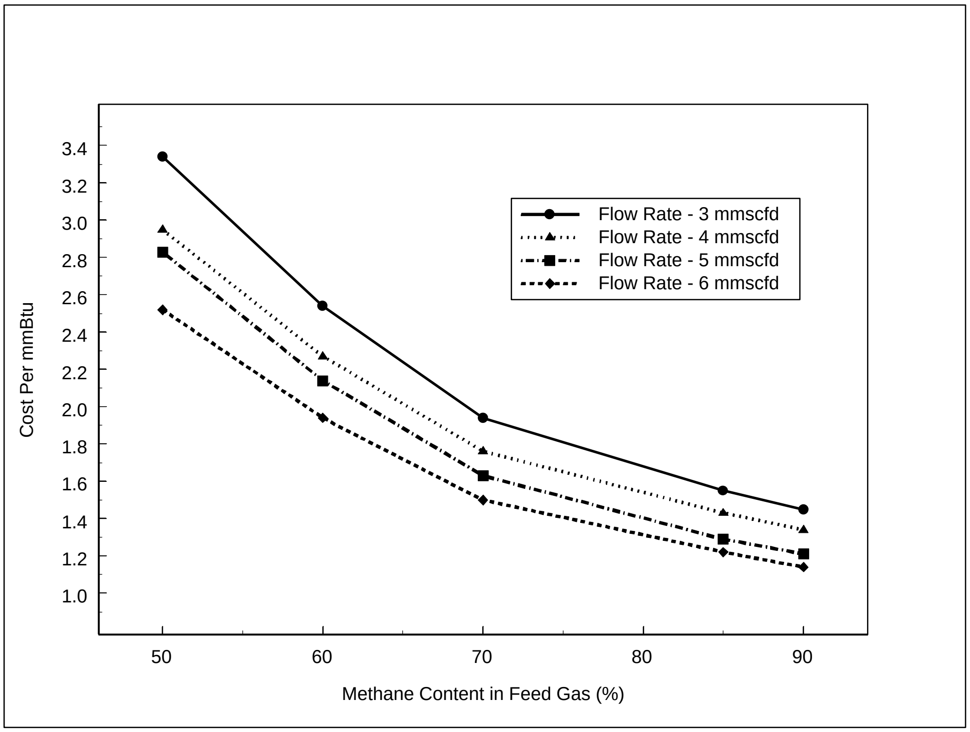

Figure 2: Low-end Costs versus Methane Concentrations in the Feed Gas

Figures 3 and 4 show plots of the high-end costs versus flow rates at various methane inlet concentrations and versus methane content in feed gas at various flow rates. The trends of these high-end estimates are the same as the low-end costs.

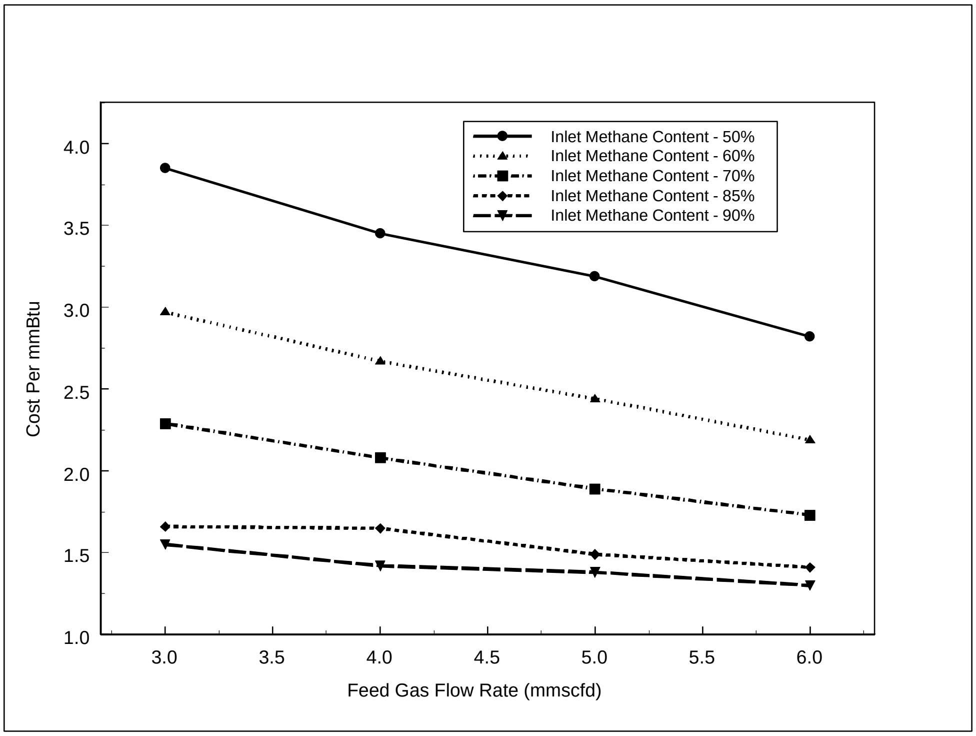

Figure 3: High-end Costs versus Feed Gas Flow Rates

3.6.3 One Plant versus Two

Figure 1 shows the rather steep cost increases for smaller daily flows. If two or more gob gas flows could be gathered at one larger plant site the operation might be much more economical, depending on the distance of the piped raw gas. Figure 5 is a simple break-even analysis that illustrates that concept. The analysis takes the unit cost of enriching two streams of 3 mmscfd at 85 percent methane at two separate PSA plants ($1.55 from Table 3) and compares it with the unit cost of the same gas streams that are processed at one 6 mmscfd plant for ($1.22 from Table 3) plus the costs of compressing and piping half of the gas stream over various distances representing the distances between two hypothetical mine sites. The break-even analysis shows that gas may be sent up to 8 miles to consolidate flows with an 8 inch shallow burial pipe before it becomes less expensive to build two plants. Assuming that the project uses a 6 inch shallow burial pipe, gas may be piped almost 9 miles. If the 6 inch pipe is not buried, then gas may be conveyed more than 15 miles. The analysis did not take into account the difficulties or costs associated with right-of-way acquisition where the mine does not control the land between the two sites.

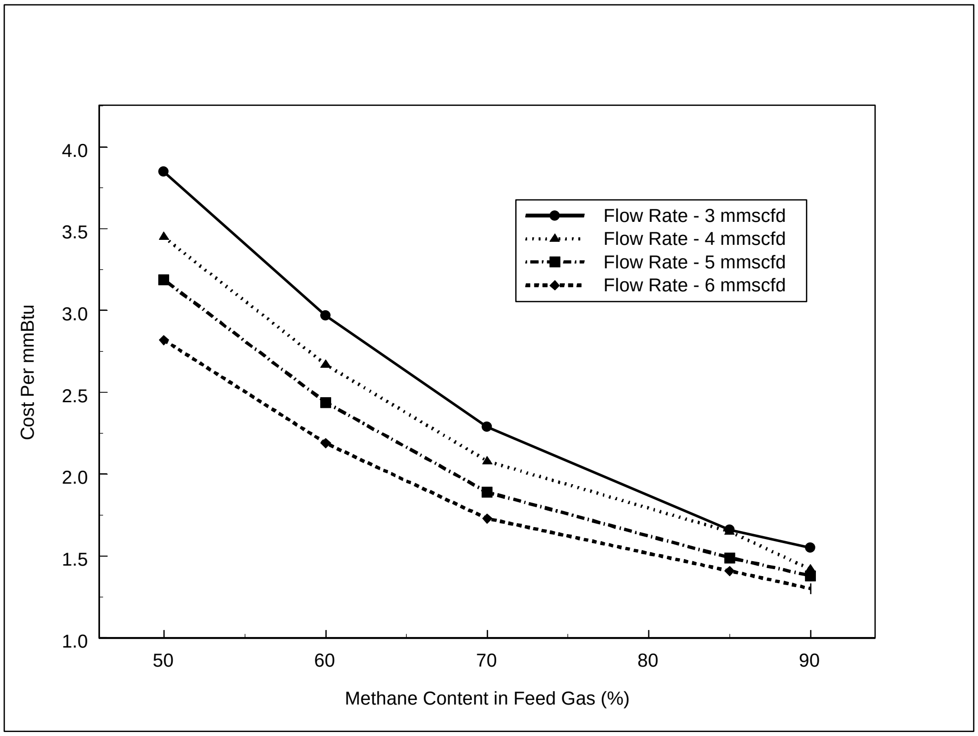

Figure 4: High-end Costs versus Methane Concentrations in the Feed Gas

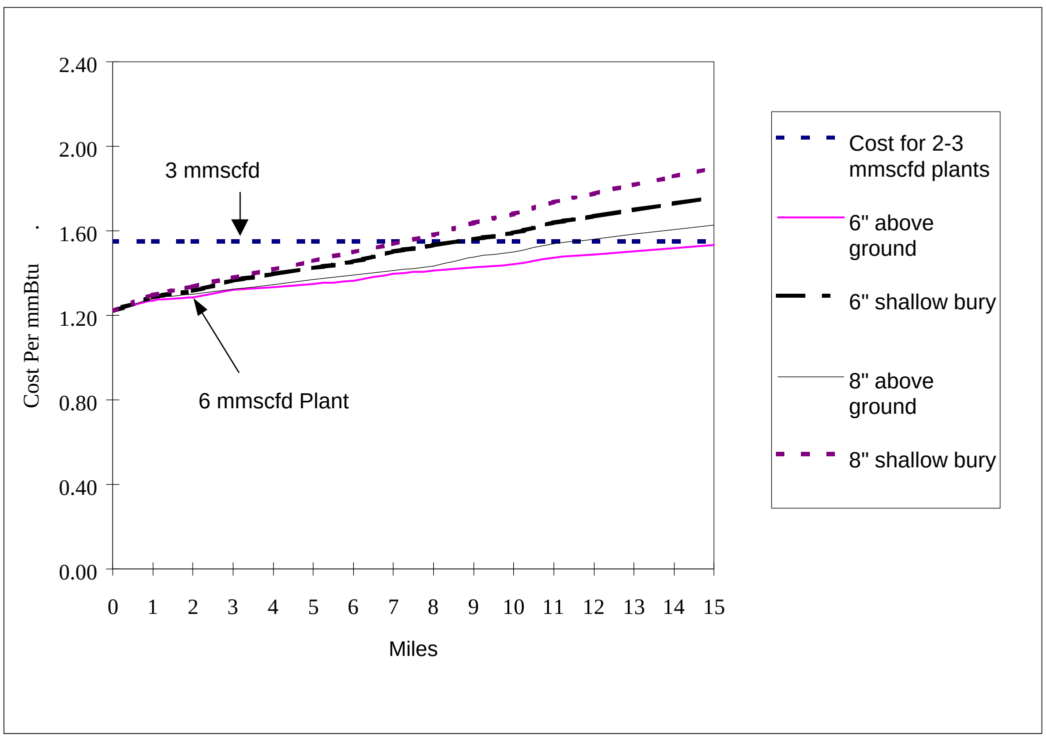

Figure 5: Cost Comparison for Piped Gob Gas to a 6 mmscfd Plant versus Two 3 mmscfd Plants

3.6.4 Cash Flow Analyses

Analysts selected two project configurations that are financially attractive and one that is not quite marginally attractive for further examination in a discounted cash flow format. Tables 2.1, 2.2, and 2.3 are in Appendix B. The two cases using 85 percent feed gas (Tables 2.2 and 2.3) show pre-tax internal rates of return between 26 percent and 33 percent that would be interesting to many investors. The lower 26 percent return results from using the high-end costs and 5 mmscfd v. low-end costs and 6 mmscfd for the 33 percent return. The 70 percent methane case with a daily flow of 5 mmscfd shows a pre-tax return of 22 percent which is only marginally attractive, even using low-end costs. Of course this result would improve somewhat if the project were leveraged with debt financing. Profitability could also improve if there were no royalty requirement or if gas prices were to increase.

3.6.5 Future Cost Trends

In general, the cost data reveal that the larger projects with smaller amounts of impurities are the only profitable projects. This picture is very similar to the 1993 assessment of gob gas enrichment. If anything, plants may be somewhat less expensive now, but cost estimates presented in either report did not result from actual integrated plant field experience (because there has been none), so small trends are difficult to verify. One could speculate that enrichment costs may decrease once field operations begin, allowing the smaller, more contaminated gas streams to be profitably upgraded. Some reasons might be:

- As more systems go on-line, technical uncertainties and risks will lessen, which may allow reduced markups.
- Competition among several system suppliers of three different technologies will maintain pressure on costs.
- Standardization of plant modules will contain manufacturing costs.
- As operators gain more field experience they may be able to take advantage of remote monitoring and process adjustment to reduce operator costs.
- Mine operators may see opportunities to gather larger gob gas flows and to maintain higher methane percentages in the feed gas to save processing dollars.

3.6.6 Cost Study Conclusions

Cost estimates of the technologies indicate that gob gas enrichment projects that sell upgraded gas into the natural gas transmission or distribution market may be cost effective relative to current natural gas prices if 80 percent methane feed gas is consistently available in daily gas flows of 5 mmscfd or higher. This judgment relies on the fact that the analyses used conservative estimates of capital and operating costs for typical plants operating under an assumed set of operating conditions. With this level of cost estimation, it is not possible to choose among the three technologies. Enrichment costs are very sensitive to project size and methane content. If two or more projects are within about 10 miles of one another, the developer should study the possibility of enriching the two gas streams together at one common plant.

4.0 CONCLUSIONS

The following sections summarize the findings of this report.

At this writing there has been no full scale demonstration of gob gas enrichment, but this situation may be changing. Opportunities exist to develop facilities because many mines have gob gas flows that would support financially attractive projects. Three basic technologies for nitrogen rejection have been proven and are being sold by a number of vendors for use on substandard natural gas. Gob gas enrichment, however, requires rejection of oxygen, carbon dioxide, and water vapor in addition to nitrogen, and all four processes would have to combine in an integrated plant. The coal company, system vendor, or project developer that first assumes the risks and goes through the process of implementing an integrated enrichment plant will have established a dominant position in a new market.

4.2 System Suppliers Willing to Demonstrate

Suppliers of nitrogen rejection technologies are ready for the opportunity (and are even beginning) to demonstrate full scale gob gas enrichment in an integrated plant using processes that have been proven individually on other feedstocks.

4.3 Technical Concerns

There are a number of technical concerns relating to the ability of an integrated enrichment plant to handle gob gas in spite of the confidence expressed by system suppliers. For example, the plant must be tolerant to the flow and quality fluctuations inherent with gob gas; it must be able to function in the presence of other contaminants such as oxygen and carbon dioxide; and it must remove any possibility of accumulating explosive combinations of methane and oxygen. Plant designers need to develop a complex control architecture for remote trouble free operation.

4.4 Cost Effective Projects

Assuming that technical concerns can be overcome and that cost estimates generated for this report are reasonable, there is a good likelihood that gob gas projects with a certain range of gas quantity and quality will be cost effective and attractive to investors on their own merit. It is also possible that capital and operating costs will improve after mine operators and system suppliers gain field experience. To ensure profitable projects, other factors must be positive as well:

- Projects must maintain feed gas supply within reasonable quality and quantity ranges.

- There must be a cooperative pipeline customer within a reasonable distance from the mine.

- The mine operator must arrange to keep a high percentage of revenues with minimal payments for royalties and taxes.

4.5 Effects of Natural Gas Prices on Profitability

At current gas prices (the analysis assumed that the pipeline would pay $2.00 per mmBtu and charge $0.30 for a net of $1.70 per mmBtu), only the mines that can produce gob gas flows above 4 mmscfd with methane content consistently better than 80 percent can expect to develop strong projects. Figures 1 and 2 are useful for scaling off the impact of changing the gas price. For example, if gas prices were to increase by 15 percent from current levels, a gob gas with close to 70 percent methane might become economically feasible for the same sized project, or a 3 mmscfd daily gas flow project may become attractive with the 80 percent quality feed gas.

If natural gas prices were to move even further upward, the higher revenues would allow projects with smaller and/or lower quality gas supplies to succeed. For example, if net revenues (after transportation costs) were to permanently rise above $2.20 per mmBtu (about 30 percent above the $1.70 level), most or all of the projects summarized on Table 3 would be financially attractive.

4.6 Market Incentives

Although one commercial scale plant may soon be on-line, the industry has been slow to take advantage of available technology. What will accelerate the establishment of more projects? What will sustain the industry so that many facilities go on-line after the first few? It may be good enough for a system supplier to provide guarantees to a customer to protect against economic loss. But if the plant turns out to be unsatisfactory, and the vendor must return the purchase price, a mine operator would still not be able to recover the costs associated with management time, training time, and opportunity losses (from not pursuing other gas recovery and use options).

The chances of a facility getting built will depend greatly on the monetary rewards available from upgrading and selling the methane. The cost studies show that only the larger facilities with high methane content in the feed gas will have a good chance of providing a fair rate of return to the investor. Smaller projects, or any project with medium to low methane content will most likely have to depend on one or more incentives that would have the effect of reducing investor risk and raising investment returns. Possible incentive mechanisms include the following:

- Section 29 Non-Conventional Fuel Tax Credits. This federal tax program is ending, but there are some pre-existing wells that may still be able to take advantage of the credits.

- Greenhouse Gas Emission Reduction Reports. Mine operators may be able to take advantage of these reports for financing projects that mitigate global warming. Projects that use methane that would otherwise have gone to waste are especially good candidates for funds from large utility or industrial firms that choose to offset their own greenhouse gas emissions. If global warming reports, at current full value, could support any one of the projects modeled in this report, each would show a robust and financeable cash flow statement.

- Risk Sharing Using Project Structure. Often a creative contractual structuring of project entities and roles will provide incentives for project implementation. In a joint venture or a less formal relationship between a mine operator and a system supplier, each party may take on assigned risks and rewards that are commensurate with its primary function.

- The mine operator may assume the "gas risk" - the responsibility that gob gas of acceptable quality and rate of flow will consistently flow to the enrichment plant. Perhaps a "put or pay" clause that penalizes the operator when gas deliveries are below specific limits could enforce compliance.

- The system supplier may accept the technical risk that the plant will perform up to specified standards. This entity may also provide a maintenance contract with an extended warrantee of performance as long as that contract is in place.

- Both parties could share in the financial risk by forgoing receipt of expected payments during periods when project cash flow cannot meet debt service (or other payments for capital).

The alternative energy industry has produced many innovative incentive mechanisms that have encouraged implementation of projects that otherwise would have stalled in an early phase. Some useful strategies that will apply specifically to gob gas enrichment projects appear in a new handbook published by EPA entitled A Guide to Financing Coalbed Methane Projects.

4.7 Financial Assistance: State, Local, and Federal

CMOP recognized that one barrier to coal mine methane recovery is difficulty in obtaining financing for economically sound methane recovery projects. CMOP published a document entitled Finance Opportunities for Coal Mine Methane Projects: A Guide to Federal Assistance and two guides for state and local finance opportunities (in Pennsylvania and West Virginia). These describe a broad scope of programs and funds available from the respective governments. Most federal assistance is in the form of grants and loans to state agencies for reallocation to local businesses. The guides provide an overview of assistance programs and profiles of the most promising federal programs for assisting coal mine methane projects. These guides are available from CMOP (see contact information in Appendix F).

4.8 CMOP Assistance

CMOP offers help to developers of methane use projects. The assistance ranges from activities that support specific projects to documents that help developers work through common problems. The following is a list of potential assistance:

- Pre-feasibility assessments.

- Solutions to legal or regulatory obstacles.

- Information on interested venture partners.

- Identification of potential financial sources.
- Advice on overcoming market entry barriers.
- Networking to share publicly available technical innovations.
- Public recognition for voluntary achievement.
- Seminars and workshops on selected subjects.

APPENDIX A - ASSUMPTIONS USED IN THE COST ANALYSES

1.0 ASSUMPTIONS USED IN THE COST ANALYSES

The following sections describe the methods and parameters used in the cost analyses. This information supplements the discussions in Section 3 of the report.

Presentation Format

The analyses appear in Appendix B in two formats. The first (B.1) presents candidate scenarios for a range of flows and methane contents in a simple unit cost analysis using first year operating costs and an annual capital recovery factor of 0.28 times the total investment cost (which represents a 25 percent rate of return for a ten year life of project). Each table has a column for low-end and high-end costs. The second analysis format (B.2) is a fifteen year cash flow proforma statement showing expected internal rates of return for a sampling of the more promising of the scenarios from B.1. This is the fairest way to compare costs of one project scenario to another. One of the cash flow statements use high-end costs and two use low-end costs.

Another purpose of this exercise is to demonstrate to mine operators whether or not an enrichment system could be economically attractive at their location. While no one actual mine situation will fit the selected criteria, interested mine operators can change assumptions where appropriate to test applicability of a particular system.

Gas Production

There are 20 cases in Appendix B.1, which are all permutations of two variables: input flows of 3, 4, 5, and 6 mmscfd of gob gas averaging 50, 60, 70, 85, or 90 percent methane. The sample cash flow analyses assume that the duration of gob gas production is at least as long as the fifteen year project economic life. Estimated average available *sales gas* flows associated with each discrete feed input, take into account average methane content, process losses, and methane consumption for the compressors.

System Availability

There are a number of reasons why a complex enrichment facility cannot produce to its full capacity 100 percent of the time. First, the gob wells themselves cannot always produce expected qualities and quantities of feed gas because of natural fluctuation and well maintenance programs. Second, the gathering system will experience outages and periods of low flow. Third, the integrated enrichment facility with its many components and compression stages must have idle periods for scheduled and unscheduled outages. Fourth, the delivery system and the pipeline’s ability to always accept sales gas will experience interruptions. To mitigate the feed gas fluctuations a mine operator may be able to select a plant capacity that coincides with expected periods of low flow so it will be fully employed most of the time. But for such cases, average and peak gob gas flows will exceed plant capacities so that operators must vent or flare significant quantities of gas even while the plant runs at capacity. To reflect the sum of these factors, the analysis assumes a plant availability of 90 percent.

Gas Revenue

This analysis assumes an average heat content of 980 Btu per scf for the sales gas. The assumed market price is $2.00 per mmBtu and the transportation cost paid to the pipeline is $0.30 per mmBtu, for a net revenue of $1.70 per mmBtu which is then escalated at three percent per year after year one. The mine's share of the gross gas revenue after a 12.5 percent royalty is 87.5 percent.

Sales Gas Specifications

1.	Solids	Free of
2.	Oxygen	10 ppm
3.	Nitrogen*	Max. 3 percent
4.	Carbon Dioxide*	Max. 3 percent
5.	Hydrogen Sulfide	1/4 Grain/100
6.	Total Sulfur	20 Grains/100
7.	Liquids	Free of
8.	Water Vapor	7 lbs/mmscf
9.	Hydrocarbon Dew Point	15 degrees F @ 100-1000 psi
10.	Heating Value	Min. 980 Btu/scf
11.	Temperature	Max. 120 F
12.	Delivery Pressure	100 - 800 psig

* Total Inerts (Combined) Max. 3 percent

Limits of Analysis

Since the primary intent of this analysis is to compare enrichment cases with different flows and qualities, the "borders" of the physical plant to be studied were narrowed somewhat to include only the enrichment system and a modest delivery configuration. The model assumes that the mine would already have in place a series of gob wells with low pressure blowers and some piping. It would be a small cost for most mines to complete this gathering system, and that cost fits within the contingency. Therefore, sunk costs are original well installation costs plus the costs of installing new wells during the project. Also gob well maintenance service that would be required anyway does not enter into this analysis. The model further assumes that the enrichment plant would be close to the gathering system outlet so there will be no additional gathering costs (except in the break-even analysis, Figure 5, which compares two smaller plants each located at separated mines with a larger plant). The delivery system consists of a right-of-way (ROW), a one mile pipe (assuming a 6 inch 250 psi shallow buried pipe), a 600 psi sales compressor, a metering station, and an interconnection with a natural gas pipeline totaling $150,000. Some actual interconnections may require pressures of 1000 or 1200 psi, and the additional cost of injecting at 1200 psi v. 600 is in the range of $0.20 per mmBtu.

Capitalization

For the sake of simplicity the model assumes a 100 percent equity case (i.e. with no project debt). While a project such as this could raise several types of financing and could use leverage to increase profit and decrease the impact on a mine operator's balance sheet, it would be difficult to depict a debt structure that would be applicable to all. For the convenience of a potential developer there are lines in the Cash Flow Analyses left open to calculate the impact of debt interest payments and principal repayments on annual cash flow.

Depreciation

A depreciation calculation is necessary to predict federal and state income taxes. This analysis is presented “pre-tax” (see the discussion on taxes below), so depreciation would not need to be analyzed. However, the model included it for those that wish to refine the estimates by applying their own tax situation to the project.

The majority of tangible capital costs follow the Modified Accelerated Cost Recovery System to calculate a depreciation allowance. This analysis used a seven year recovery period with the half year convention, 200 percent declining balance method, and no salvage value. Pipeline and ROW depreciation is straight line over a fifteen year useful life. The depreciation allowances stretch over the first eight years of the project using the following percentages of depreciable costs: 14.29, 24.49, 17.49, 12.49, 8.93, 8.92, 8.93, and 4.46 percent.

Operating Expenses

Operating expenses are direct and indirect costs associated with field operations and maintenance of the enrichment system, compressors, and delivery system. Costs include direct and supervisory labor, labor benefits and expenses, supplies, fuel and utilities, repair labor and expense, and other direct and indirect costs. Some of the operating expense data came from the system vendors; others, such as maintenance labor and materials, and local taxes and insurance, appear as percentages of plant cost. Personnel assumptions are one full time operator for all cases except cryogenics plants where one and one quarter operator would be needed. The model accounts for supervision labor and overheads as a standard override on labor. Operating expenses also escalate at three percent for the life of the project.

Federal and State Taxes

The analyses are all pre-tax for simplicity and because of the difficulty of selecting a representative average tax situation for each mine. As no taxes were figured, no tax credits such as depletion allowances or non-conventional fuel tax credits (Section 29 credits) appear in the analysis. In the case of Section 29 credits, there will be fewer and fewer mine operators that will be able to take advantage of them as time passes.

Miscellaneous Taxes

Each case assumes a five percent severance tax on the value of all severed minerals (in this case the mine’s share of the methane value) and an ad valorem tax at a rate of three percent of the mine’s share of the methane. This is similar to amounts that would be paid in West Virginia.

APPENDIX B - COST ANALYSIS

B.1 Unit Cost Analysis: Tables 1.1 through 1.20

B.2 Cash Flow Statements: Tables 2.1 through 2.3

Table 1.1 - 3 mmscfd, 50% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	50.00%	97.00%
Nitrogen	37.60%	3.00%
CO_2	3.00%	0.00%
Oxygen	9.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	3	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.48	0.44
Sales Gas Flow - mmscfd	1.17	1.27
mmBtu/y @ 980 Btu/scf, 90% on-line	376,658	408,851
Capital Costs (M$)		
NRU	1,230	1,590
Deoxygenation	487	696
CO_2 Removal	150	200
Water Removal	40	40
Process Compression	574	550
Sales Compression	145	120
TOTAL DIRECT PLANT	2,626	3,196
Auxiliary Costs (10%)	263	320
Install/startup (15%)	394	479
Contingency (10%)	263	320
Total Capital Cost	3,545	4,315
Ann. Cap. Recovery -10yr, 25% bef tax	993	1,208
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	53	64
Maint. Labor - 3% direct plant	79	96
Local Taxes/ Ins. - 1.5% direct plant	39	48
TOTAL OPERATING COST	266	368
TOTAL ANNUAL COST	1,259	1,576
Gas Cost: $/mmBtu	3.34	3.85

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.2 Cost Comparison - 3 mmscfd, 60% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	60.00%	97.00%
Nitrogen	29.23%	3.00%
CO2	3.00%	0.00%
Oxygen	7.77%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	3	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.43	0.4
Sales Gas Flow - mmscfd	1.43	1.54
mmBtu/y @ 980 Btu/scf, 90% on-line	460,360	495,772
Capital Costs (M$)		
NRU	1,130	1,490
Deoxygenation	403	576
CO2 Removal	150	200
Water Removal	40	40
Process Compression	526	509
Sales Compression	166	143
TOTAL DIRECT PLANT	2,414	2,958
Auxiliary Costs (10%)	241	296
Install/startup (15%)	362	444
Contingency (10%)	241	296
Total Capital Cost	3,259	3,993
Ann. Cap. Recovery -10yr, 25% bef tax	913	1,118
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	48	59
Maint. Labor - 3% direct plant	72	89
Local Taxes/ Ins. - 1.5% direct plant	36	44
TOTAL OPERATING COST	256	352
TOTAL ANNUAL COST	1,168	1,470
Gas Cost: $/mmBtu	2.54	2.97

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.3 Cost Comparison - 3 mmscfd, 70% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	70.00%	97.00%
Nitrogen	21.60%	3.00%
CO_2	3.00%	0.00%
Oxygen	5.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	3	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.38	0.36
Sales Gas Flow - mmscfd	1.70	1.83
mmBtu/y @ 980 Btu/scf, 90% on-line	547,281	589,132
Capital Costs (M$)		
NRU	1,030	1,390
Deoxygenation	280	400
CO_2 Removal	150	200
Water Removal	40	40
Process Compression	477	474
Sales Compression	190	184
TOTAL DIRECT PLANT	2,167	2,688
Auxiliary Costs (10%)	217	269
Install/startup (15%)	325	403
Contingency (10%)	217	269
Total Capital Cost	2,925	3,629
Ann. Cap. Recovery -10yr, 25% bef tax	819	1,016
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	43	54
Maint. Labor - 3% direct plant	65	81
Local Taxes/ Ins. - 1.5% direct plant	32	40
TOTAL OPERATING COST	243	335
TOTAL ANNUAL COST	1,062	1,351
Gas Cost: $/mmBtu	1.94	2.29

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.4 Cost Comparison - 3 mmscfd, 85% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	85.00%	97.00%
Nitrogen	10.00%	3.00%
CO2	3.00%	0.00%
Oxygen	2.00%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	3	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.30	0.3
Sales Gas Flow - mmscfd	2.13	2.27
mmBtu/y @ 980 Btu/scf, 90% on-line	685,711	730,781
Capital Costs (M$)		
NRU	1,030	1,200
Deoxygenation	280	330
CO2 Removal	150	150
Water Removal	40	40
Process Compression	430	429
Sales Compression	232	225
TOTAL DIRECT PLANT	2,162	2,374
Auxiliary Costs (10%)	216	237
Install/startup (15%)	324	356
Contingency (10%)	216	237
Total Capital Cost	2,919	3,205
Ann. Cap. Recovery -10yr, 25% bef tax	817	897
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	43	47
Maint. Labor - 3% direct plant	65	71
Local Taxes/ Ins. - 1.5% direct plant	32	36
TOTAL OPERATING COST	243	314
TOTAL ANNUAL COST	1,060	1,212
Gas Cost: $/mmBtu	1.55	1.66

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.5 Cost Comparison - 3 mmscfd, 90% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	90.00%	97.00%
Nitrogen	6.40%	3.00%
CO2	2.00%	0.00%
Oxygen	1.60%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	3	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.28	0.28
Sales Gas Flow - mmscfd	2.27	2.42
mmBtu/y @ 980 Btu/scf, 90% on-line	730,781	779,071
Capital Costs (M$)		
NRU	1,030	1,200
Deoxygenation	280	330
CO2 Removal	150	150
Water Removal	40	40
Process Compression	405	406
Sales Compression	248	240
TOTAL DIRECT PLANT	2,153	2,366
Auxiliary Costs (10%)	215	237
Install/startup (15%)	323	355
Contingency (10%)	215	237
Total Capital Cost	2,907	3,194
Ann. Cap. Recovery -10yr, 25% bef tax	814	894
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	43	47
Maint. Labor - 3% direct plant	65	71
Local Taxes/ Ins. - 1.5% direct plant	32	35
TOTAL OPERATING COST	243	314
TOTAL ANNUAL COST	1,057	1,208
Gas Cost: $/mmBtu	1.45	1.55

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.6 Cost Comparison - 4 mmscfd, 50% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	50.00%	97.00%
Nitrogen	37.60%	3.00%
CO2	3.00%	0.00%
Oxygen	9.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	4 available 3 inlet cap	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.56	0.5197
Sales Gas Flow - mmscfd	1.39	1.48
mmBtu/y @ 980 Btu/scf, 90% on-line	447,483	476,456
Capital Costs (M$)		
NRU	1,230	1,590
Deoxygenation	487	696
CO2 Removal	150	200
Water Removal	40	40
Process Compression	684	654
Sales Compression	179	169
TOTAL DIRECT PLANT	2,770	3,349
Auxiliary Costs (10%)	277	335
Install/startup (15%)	416	502
Contingency (10%)	277	335
Total Capital Cost	3,740	4,521
Ann. Cap. Recovery -10yr, 25% bef tax	1,047	1,266
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	55	67
Maint. Labor - 3% direct plant	83	100
Local Taxes/ Ins. - 1.5% direct plant	42	50
TOTAL OPERATING COST	274	378
TOTAL ANNUAL COST	1,321	1,644
Gas Cost: $/mmBtu	2.95	3.45

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.7 Cost Comparison - 4 mmscfd, 60% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	60.00%	97.00%
Nitrogen	29.23%	3.00%
CO2	3.00%	0.00%
Oxygen	7.77%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	4 available 3 inlet cap	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.50	0.4651
Sales Gas Flow - mmscfd	1.67	1.78
mmBtu/y @ 980 Btu/scf, 90% on-line	537,623	573,035
Capital Costs (M$)		
NRU	1,130	1,490
Deoxygenation	403	576
CO2 Removal	150	200
Water Removal	40	40
Process Compression	615	601
Sales Compression	199	189
TOTAL DIRECT PLANT	2,536	3,096
Auxiliary Costs (10%)	254	310
Install/startup (15%)	380	464
Contingency (10%)	254	310
Total Capital Cost	3,424	4,179
Ann. Cap. Recovery -10yr, 25% bef tax	959	1,170
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	51	62
Maint. Labor - 3% direct plant	76	93
Local Taxes/ Ins. - 1.5% direct plant	38	46
TOTAL OPERATING COST	262	361
TOTAL ANNUAL COST	1,221	1,531
Gas Cost: $/mmBtu	2.27	2.67

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.8 Cost Comparison - 4 mmscfd, 70% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	70.00%	97.00%
Nitrogen	21.60%	3.00%
CO2	3.00%	0.00%
Oxygen	5.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	4 available 3 inlet cap	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.43	0.4105
Sales Gas Flow - mmscfd	1.95	2.08
mmBtu/y @ 980 Btu/scf, 90% on-line	627,764	669,614
Capital Costs (M$)		
NRU	1,030	1,390
Deoxygenation	280	400
CO2 Removal	150	200
Water Removal	40	40
Process Compression	548	548
Sales Compression	220	210
TOTAL DIRECT PLANT	2,268	2,789
Auxiliary Costs (10%)	227	279
Install/startup (15%)	340	418
Contingency (10%)	227	279
Total Capital Cost	3,062	3,765
Ann. Cap. Recovery -10yr, 25% bef tax	857	1,054
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	45	56
Maint. Labor - 3% direct plant	68	84
Local Taxes/ Ins. - 1.5% direct plant	34	42
TOTAL OPERATING COST	248	341
TOTAL ANNUAL COST	1,106	1,395
Gas Cost: $/mmBtu	1.76	2.08

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.9 Cost Comparison - 4 mmscfd, 85% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	85.00%	97.00%
Nitrogen	10.00%	3.00%
CO_2	3.00%	0.00%
Oxygen	2.00%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	4 available 3 inlet cap	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.33	0.33
Sales Gas Flow - mmscfd	2.37	2.52
mmBtu/y @ 980 Btu/scf, 90% on-line	762,974	811,264
Capital Costs (M$)		
NRU	1,030	1,390
Deoxygenation	280	330
CO_2 Removal	150	150
Water Removal	40	40
Process Compression	471	498
Sales Compression	258	248
TOTAL DIRECT PLANT	2,229	2,656
Auxiliary Costs (10%)	223	266
Install/startup (15%)	334	398
Contingency (10%)	223	266
Total Capital Cost	3,009	3,586
Ann. Cap. Recovery -10yr, 25% bef tax	842	1,004
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	45	53
Maint. Labor - 3% direct plant	67	80
Local Taxes/ Ins. - 1.5% direct plant	33	40
TOTAL OPERATING COST	246	333
TOTAL ANNUAL COST	1,089	1,337
Gas Cost: $/mmBtu	1.43	1.65

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.10 Cost Comparison - 4 mmscfd, 90% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	90.00%	97.00%
Nitrogen	6.40%	3.00%
CO2	2.00%	0.00%
Oxygen	1.60%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	4 available 3 inlet cap	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.30	0.3
Sales Gas Flow - mmscfd	2.51	2.67
mmBtu/y @ 980 Btu/scf, 90% on-line	808,044	859,553
Capital Costs (M$)		
NRU	1,030	1,200
Deoxygenation	280	280
CO2 Removal	150	150
Water Removal	40	40
Process Compression	446	468
Sales Compression	272	262
TOTAL DIRECT PLANT	2,218	2,400
Auxiliary Costs (10%)	222	240
Install/startup (15%)	333	360
Contingency (10%)	222	240
Total Capital Cost	2,994	3,240
Ann. Cap. Recovery -10yr, 25% bef tax	838	907
OPERATING COSTS (M$/YR)		
Consumables	15	35
Utilities	30	35
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	44	48
Maint. Labor - 3% direct plant	67	72
Local Taxes/ Ins. - 1.5% direct plant	33	36
TOTAL OPERATING COST	246	316
TOTAL ANNUAL COST	1,084	1,223
Gas Cost: $/mmBtu	1.34	1.42

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.11 Cost Comparison - 5 mmscfd, 50% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	50.00%	97.00%
Nitrogen	37.60%	3.00%
CO_2	3.00%	0.00%
Oxygen	9.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	5	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.71	0.7081
Sales Gas Flow - mmscfd	1.99	2.12
mmBtu/y @ 980 Btu/scf, 90% on-line	640,641	682,492
Capital Costs (M$)		
NRU	1,671	2,160
Deoxygenation	696	870
CO_2 Removal	200	200
Water Removal	50	50
Process Compression	1,006	939
Sales Compression	219	224
TOTAL DIRECT PLANT	3,842	4,444
Auxiliary Costs (10%)	384	444
Install/startup (15%)	576	667
Contingency (10%)	384	444
Total Capital Cost	5,187	5,999
Ann. Cap. Recovery -10yr, 25% bef tax	1,452	1,680
OPERATING COSTS (M$/YR)		
Consumables	30	60
Utilities	50	60
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	77	89
Maint. Labor - 3% direct plant	115	133
Local Taxes/ Ins. - 1.5% direct plant	58	67
TOTAL OPERATING COST	362	499
TOTAL ANNUAL COST	1,815	2,179
Gas Cost: $/mmBtu	2.83	3.19

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.12 Cost Comparison - 5 mmscfd, 60% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	60.00%	97.00%
Nitrogen	29.23%	3.00%
CO_2	3.00%	0.00%
Oxygen	7.77%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	5	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.63	0.63502
Sales Gas Flow - mmscfd	2.43	2.59
mmBtu/y @ 980 Btu/scf, 90% on-line	782,290	833,799
Capital Costs (M$)		
NRU	1,535	2,024
Deoxygenation	576	719
CO_2 Removal	200	200
Water Removal	50	50
Process Compression	892	868
Sales Compression	257	260
TOTAL DIRECT PLANT	3,509	4,121
Auxiliary Costs (10%)	351	412
Install/startup (15%)	526	618
Contingency (10%)	351	412
Total Capital Cost	4,737	5,564
Ann. Cap. Recovery -10yr, 25% bef tax	1,326	1,558
OPERATING COSTS (M$/YR)		
Consumables	30	60
Utilities	50	60
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	70	82
Maint. Labor - 3% direct plant	105	124
Local Taxes/ Ins. - 1.5% direct plant	53	62
TOTAL OPERATING COST	345	478
TOTAL ANNUAL COST	1,672	2,036
Gas Cost: $/mmBtu	2.14	2.44

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.13 Cost Comparison - 5 mmscfd, 70% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	70.00%	97.00%
Nitrogen	21.60%	3.00%
CO2	3.00%	0.00%
Oxygen	5.40%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	5	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.56	0.56194
Sales Gas Flow - mmscfd	2.88	3.07
mmBtu/y @ 980 Btu/scf, 90% on-line	927,158	988,325
Capital Costs (M$)		
NRU	1,399	1,889
Deoxygenation	400	500
CO2 Removal	200	200
Water Removal	50	50
Process Compression	790	802
Sales Compression	301	301
TOTAL DIRECT PLANT	3,141	3,741
Auxiliary Costs (10%)	314	374
Install/startup (15%)	471	561
Contingency (10%)	314	374
Total Capital Cost	4,240	5,051
Ann. Cap. Recovery -10yr, 25% bef tax	1,187	1,414
OPERATING COSTS (M$/YR)		
Consumables	30	60
Utilities	50	60
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	63	75
Maint. Labor - 3% direct plant	94	112
Local Taxes/ Ins. - 1.5% direct plant	47	56
TOTAL OPERATING COST	327	453
TOTAL ANNUAL COST	1,514	1,867
Gas Cost: $/mmBtu	1.63	1.89

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.14 Cost Comparison - 5 mmscfd, 85% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	85.00%	97.00%
Nitrogen	10.00%	3.00%
CO_2	3.00%	0.00%
Oxygen	2.00%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	5	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.45	0.45232
Sales Gas Flow - mmscfd	3.59	3.83
mmBtu/y @ 980 Btu/scf, 90% on-line	1,155,729	1,232,992
Capital Costs (M$)		
NRU	1,399	1,889
Deoxygenation	400	460
CO_2 Removal	200	200
Water Removal	50	50
Process Compression	659	713
Sales Compression	383	375
TOTAL DIRECT PLANT	3,092	3,686
Auxiliary Costs (10%)	309	369
Install/startup (15%)	464	553
Contingency (10%)	309	369
Total Capital Cost	4,174	4,977
Ann. Cap. Recovery -10yr, 25% bef tax	1,169	1,393
OPERATING COSTS (M$/YR)		
Consumables	30	60
Utilities	50	60
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	62	74
Maint. Labor - 3% direct plant	93	111
Local Taxes/ Ins. - 1.5% direct plant	46	55
TOTAL OPERATING COST	325	450
TOTAL ANNUAL COST	1,493	1,843
Gas Cost: $/mmBtu	1.29	1.49

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

Table 1.15 Cost Comparison - 5 mmscfd, 90% Methane

Gas Composition And Flow Rate		
	Inlet Gas	**Outlet Gas**
Methane	90.00%	97.00%
Nitrogen	6.40%	3.00%
CO2	2.00%	0.00%
Oxygen	1.60%	0.00%
Water	Saturated	Dry
Gob Gas Flow Rate (Gross) mmscfd	5	-
Technology		
	Low End	**High End**
Sales Flow Calculations		
Gas Usage For Compressors	0.41	0.41578
Sales Gas Flow - mmscfd	3.83	4.08
mmBtu/y @ 980 Btu/scf, 90% on-line	1,232,992	1,313,474
Capital Costs (M$)		
NRU	1,399	1,889
Deoxygenation	400	400
CO2 Removal	200	200
Water Removal	50	50
Process Compression	621	685
Sales Compression	415	404
TOTAL DIRECT PLANT	3,085	3,628
Auxiliary Costs (10%)	309	363
Install/startup (15%)	463	544
Contingency (10%)	309	363
Total Capital Cost	4,165	4,897
Ann. Cap. Recovery -10yr, 25% bef tax	1,166	1,371
OPERATING COSTS (M$/YR)		
Consumables	30	60
Utilities	50	60
Oper Labor With Benefits	40	40
Supv & Overheads	50	50
Maint. Materials - 2% direct plant	62	73
Maint. Labor - 3% direct plant	93	109
Local Taxes/ Ins. - 1.5% direct plant	46	54
TOTAL OPERATING COST	324	446
TOTAL ANNUAL COST	1,491	1,817
Gas Cost: $/mmBtu	1.21	1.38

*Blended PSA, cryogenic, and solvent absorption costs determine low end and high end costs.
"Low End" technology achieves lower methane recovery and requires higher compression costs.

CASH FLOW STATEMENT ($000)	TABLE 2.1 CASE: 5 mmscfd, 70% Methane, low-end cost (TABLE 1.13)															
	YEAR>>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
REVENUES *																
Gas Sales - @ 1.70/mmBtu, 90% on line	927,158	1,576	1,623	1,672	1,722	1,774	1,827	1,882	1,938	1,997	2,057	2,118	2,182	2,247	2,315	2,384
Minus Royalty @ 12.5%		197	203	209	215	222	228	235	242	250	257	265	273	281	289	298
TOTAL REVENUES		1,379	1,421	1,463	1,507	1,552	1,599	1,647	1,696	1,747	1,799	1,853	1,909	1,966	2,025	2,086
OPERATING COSTS *																
Consumables		30	31	32	33	34	35	36	37	38	39	40	42	43	44	45
Utilities		50	52	53	55	56	58	60	61	63	65	67	69	71	73	76
Oper Labor w benefits		40	41	42	44	45	46	48	49	51	52	54	55	57	59	61
Supv & overheads		50	52	53	55	56	58	60	61	63	65	67	69	71	73	76
Maint materials - 2% direct plant		63	65	67	69	71	73	75	77	80	82	85	87	90	93	95
Maint labor - 3% direct plant		94	97	100	103	106	109	112	116	119	123	126	130	134	138	142
Local Taxes/Ins - 1.5% direct plant		47	48	50	51	53	54	56	58	60	61	63	65	67	69	71
Severance & Ad Val. Taxes - 8% revs.		110	114	117	121	124	128	132	136	140	144	148	153	157	162	167
TOTAL OPERATING COSTS		484	499	514	529	545	561	578	596	614	632	651	670	691	711	733
OPERATING INCOME		895	922	949	978	1,007	1,037	1,068	1,101	1,134	1,168	1,203	1,239	1,276	1,314	1,353
NON OPERATING EXPENSE																
Depreciation		621	1,053	757	545	394	393	394	204	15	15	0	0	0	0	0
Interest Expense**																
Total Non Operating Expense		621	1,053	757	545	394	393	394	204	15	15	0	0	0	0	0
PRETAX INCOME		274	-132	193	433	613	644	675	896	1,119	1,153	1,203	1,239	1,276	1,314	1,353
Adjust to Pretax Cash Basis																
Capital Cost	-4,240															
Delivery System	-150															
Less: Senior Debt Amortization**																
Depreciation		621	1,053	757	545	394	393	394	204	15	15	0	0	0	0	0
NET CASH FLOW (BEFORE TAX)	-4,390	895	922	949	978	1,007	1,037	1,068	1,101	1,134	1,168	1,203	1,239	1,276	1,314	1,353
		[10%]		[20%]		[30%]										
Net Present Value Profile		3,296		284		-905										
Internal Rate of Return	22%															

* Simplified cash flow, assumes prompt receipt of revenues and payment of expenses.

* * Present case assumes no project debt, but interest and principal amortization space is left for project sponsor's use.

CASH FLOW STATEMENT ($000)	TABLE 2.2 CASE: 5 mmscfd, 85% Methane, high-end cost (TABLE 1.14)															
	YEAR>>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
REVENUES *																
Gas Sales - @ 1.70/mmBtu, 90% on line	1,232,992	2,096	2,159	2,224	2,290	2,359	2,430	2,503	2,578	2,655	2,735	2,817	2,901	2,989	3,078	3,171
Minus Royalty @ 12.5%		262	270	278	286	295	304	313	322	332	342	352	363	374	385	396
TOTAL REVENUES		1,834	1,889	1,946	2,004	2,064	2,126	2,190	2,256	2,323	2,393	2,465	2,539	2,615	2,693	2,774
OPERATING COSTS *																
Consumables		60	62	64	66	68	70	72	74	76	78	81	83	86	88	91
Utilities		60	62	64	66	68	70	72	74	76	78	81	83	86	88	91
Oper Labor w benefits		40	41	42	44	45	46	48	49	51	52	54	55	57	59	61
Supv & overheads		50	52	53	55	56	58	60	61	63	65	67	69	71	73	76
Maint materials - 2% direct plant		74	76	79	81	83	86	88	91	94	97	99	102	106	109	112
Maint labor - 3% direct plant		111	114	118	121	125	129	133	137	141	145	149	154	158	163	168
Local Taxes/Ins - 1.5% direct plant		55	57	58	60	62	64	66	68	70	72	74	76	78	81	83
Severance & Ad Val. Taxes - 8% revs.		147	151	156	160	165	170	175	180	186	191	197	203	209	215	222
TOTAL OPERATING COSTS		597	615	633	652	672	692	713	734	756	779	802	826	851	876	903
OPERATING INCOME		1,237	1,274	1,313	1,352	1,393	1,434	1,477	1,522	1,567	1,614	1,663	1,713	1,764	1,817	1,872
NON OPERATING EXPENSE																
Depreciation		726	1,234	885	637	459	459	459	237	15	15	0	0	0	0	0
Interest Expense**																
Total Non Operating Expense		726	1,234	885	637	459	459	459	237	15	15	0	0	0	0	0
PRETAX INCOME		511	41	427	715	933	975	1,018	1,285	1,552	1,599	1,663	1,713	1,764	1,817	1,872
Adjust to Pretax Cash Basis																
Capital Cost	-4,977															
Delivery System	-150															
Less: Senior Debt Amortization**																
Depreciation		726	1,234	885	637	459	459	459	237	15	15	0	0	0	0	0
NET CASH FLOW (BEFORE TAX)	-5,127	1,237	1,274	1,313	1,352	1,393	1,434	1,477	1,522	1,567	1,614	1,663	1,713	1,764	1,817	1,872
		[10%]		[20%]		[30%]										
Net Present Value Profile		5,415		1,180		-526										
Internal Rate of Return	26%															

* Simplified cash flow, assumes prompt receipt of revenues and payment of expenses.

* * Present case assumes no project debt, but interest and principal amortization space is left for project sponsor's use.

CASH FLOW STATEMENT ($000)	TABLE 2.3 CASE: 6 mmscfd, 85% Methane, low-end cost (TABLE 1.19)															
	YEAR>>	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
REVENUES *																
Gas Sales - @ 1.70/mmBtu, 90% on line	1,268,404	2,156	2,221	2,288	2,356	2,427	2,500	2,575	2,652	2,732	2,813	2,898	2,985	3,074	3,167	3,262
Minus Royalty @ 12.5%		270	278	286	295	303	312	322	331	341	352	362	373	384	396	408
TOTAL REVENUES		1,887	1,943	2,002	2,062	2,124	2,187	2,253	2,320	2,390	2,462	2,536	2,612	2,690	2,771	2,854
OPERATING COSTS *																
Consumables		30	31	32	33	34	35	36	37	38	39	40	42	43	44	45
Utilities		50	52	53	55	56	58	60	61	63	65	67	69	71	73	76
Oper Labor w benefits		40	41	42	44	45	46	48	49	51	52	54	55	57	59	61
Supv & overheads		50	52	53	55	56	58	60	61	63	65	67	69	71	73	76
Maint materials - 2% direct plant		64	66	68	70	72	74	76	79	81	84	86	89	91	94	97
Maint labor - 3% direct plant		96	99	102	105	108	111	115	118	122	125	129	133	137	141	145
Local Taxes/Ins - 1.5% direct plant		48	49	51	52	54	56	57	59	61	63	65	66	68	70	73
Severance & Ad Val. Taxes - 8% revs.		151	155	160	165	170	175	180	186	191	197	203	209	215	222	228
TOTAL OPERATING COSTS		529	545	561	578	595	613	632	651	670	690	711	732	754	777	800
OPERATING INCOME		1,358	1,399	1,441	1,484	1,528	1,574	1,621	1,670	1,720	1,772	1,825	1,880	1,936	1,994	2,054
NON OPERATING EXPENSE																
Depreciation		635	1078	774	557	403	402	403	209	15	15	0	0	0	0	0
Interest Expense**																
Total Non Operating Expense		635	1078	774	557	403	402	403	209	15	15	0	0	0	0	0
PRETAX INCOME		722	320	666	927	1,126	1,172	1,219	1,461	1,705	1,757	1,825	1,880	1,936	1,994	2,054
Adjust to Pretax Cash Basis																
Capital Cost	-4,341															
Delivery System	-150															
Less: Senior Debt Amortization**																
Depreciation		635	1,078	774	557	403	402	403	209	15	15	0	0	0	0	0
NET CASH FLOW (BEFORE TAX)	-4,491	1,358	1,399	1,441	1,484	1,528	1,574	1,621	1,670	1,720	1,772	1,825	1,880	1,936	1,994	2,054
		[10%]		[20%]		[30%]										
Net Present Value Profile		6,974		2,240		296										
Internal Rate of Return	33%															

* Simplified cash flow, assumes prompt receipt of revenues and payment of expenses.

* * Present case assumes no project debt, but interest and principal amortization space is left for project sponsor's use.

APPENDIX C - REFERENCES

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APPENDIX D - CONTACT INFORMATION

Contact List

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1.2 Nitrotec Engineering
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1.3 Advanced Extraction Technologies, Inc.
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Houston, TX 77060
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1.4 Darnell Engineering Corporation
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ATTN: Mr. Quinton L. Darnell, 713 999-0123

1.5 Schedule A, Inc.
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Houston, TX 77036-8229
ATTN: Mr. Pierre E. Lugosch, 713 777-7771

1.6 BOC Group
100 Mountain Avenue
Murray Hill, NJ 07974
ATTN: Dr. Art Shirley, 908 771-6104, Fax 908 771-6113

1.7 BCCK Engineering Inc.
2500 N. Big Spring
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Midland, TX 79705
ATTN: Mr. R. Clark Butts, Pres., 915 685-6095

2. Nitrogen Rejection - (In development)

2.1 Bend Research, Inc.
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ATTN: Mr. David Lyon, 541 382-4100, Fax 541 382-2713

2.2 Gas Separation Technology
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Suite 400
Golden, CO 80226
ATTN: Mr. Major W. Seery, 303 232-0658

2.3 Northwest Fuel Development
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Lake Oswego, OR 97035
ATTN: Peet Soot, Pres., 503 699-9836

3. Oxygen Removal Equipment

3.1 Optimized Process Design
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Katy, TX 77493
ATTN: Mr. Chuck DeWees, 281 371-7500

4. Carbon Dioxide Removal Equipment

4.1 Sivalls, Inc.
2200 E. 2nd Street
Odessa, TX 79761
ATTN: Mr. William J. Lawallen, 915 337-3571

5. Other

5.1 Waukesha-Pearce Industries, Inc. (Compressor Manufacturer)
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Houston, TX 77035
ATTN: Mr. John R. Burrows, 713 723-1050

5.2 Gas Research Institute (GRI)
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APPENDIX E -

TECHNICAL EVALUATIONS OF ENRICHMENT PROCESSES

Technical Evaluations of Enrichment Processes

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Contents

Introduction

Coal-mine gob gas usually contains nitrogen, carbon dioxide, oxygen and water vapor, in addition to methane. Typical pipeline specifications for natural gas allow only four percent inerts in the gas. Often, the specifications for oxygen (< 10 ppm) are stringent. Thus, the following processes are necessary for the enrichment of gob gas to pipeline quality.

1. Nitrogen rejection
2. Deoxygenation
3. Carbon dioxide removal
4. Removal of water vapor

Nitrogen rejection is the most difficult and the most expensive component of the gob gas enrichment technology. Oxygen removal can also be difficult because removal of higher than 1.5 percent oxygen in the feed gas leads to additional problems due to excessive temperatures in the deoxygenation unit. Also, O_2 must be completely removed to meet many pipeline specifications. The most difficult aspect of all the gob gas enrichment technologies is feed gas variability both in terms of flow rate and composition. This technical analysis was undertaken to evaluate the technical feasibility of gob gas enrichment technologies operating under field conditions. The objective was to define the range of operability of the enrichment technologies by calculating detailed material and energy balances. These calculations were also expected to identify if gas flammability might be of concern in any of the process units.

Process Evaluation

The technical evaluations performed on three different integrated processes for the enrichment of gob gas. The three approaches differed only in terms of their nitrogen rejection units (NRU). The NRU methods were:

1. Cryogenics
2. The lean oil process or selective absorption
3. Pressure swing adsorption process

The base case evaluations consisted of enriching a 3 mmscfd feed containing the following gases (by volume): 70 percent methane, 3 percent carbon dioxide, 21.6 percent nitrogen, 5.4 percent oxygen, and saturated with water vapor. Nitrogen, oxygen and carbon dioxide are the normal contaminants in gob gas streams. The level of carbon dioxide is usually higher in gob gas than in air because carbon dioxide is a typical constituent of coal seam gas. The carbon dioxide concentration varies considerably in gob gas from less than one percent to about 10 percent in most mines, even though gases from some mines (particularly, in Australia) have carbon dioxide concentrations as high as 50 percent. A concentration of 3 percent was considered “typical” for a number of coal mines and was selected on that basis. The concentrations of oxygen and nitrogen were in the same proportion as in air.

The feed gas compositions have to be converted to an absolute (wet) basis in order to perform material and energy balances. The gas composition including water vapor would then be, 67.6 percent methane, 20.9 percent nitrogen, 5.2 percent oxygen, 2.9 percent carbon dioxide and

3.1 percent water vapor. The objective of enrichment was to produce about 97 percent methane and 3 percent nitrogen in the product stream.

Once the base case comparisons were established, computer simulations were performed at three other combinations of flow rate and gas quality. This report includes process flow diagrams for each of the processes along with brief analyses.

The Cryogenics NRU

Figure 1a presents the integrated flow diagram for the cryogenics NRU. A more detailed flow sheet of only the NRU is shown in Figure 1b. The feed gas compressor in Figure 1a actually consists of two compressors and two intercoolers. Table 1 contains material and enthalpy specifications for each of the process streams. A process flow diagram and the data in Table 1 were generated using CHEMCAD, a well-established chemical process simulator developed by CHEMSTATIONS, Inc., Houston, Texas. The Department of Chemical and Fuels Engineering at the University of Utah has a special license to use the simulator for educational and research purposes. The process flow diagram was conceptualized based on process schemes suggested in reference 1 (GRI, 1991). CHEMCAD simulated the actual distillation process for the separation of nitrogen and methane using well established chemical engineering separation calculations. The process concept appears conventional. It should be noted, however, that there are a number of process units sequenced together. The concentrations of carbon dioxide and water are higher at the exit of the deoxygenation unit than the feed to the unit since, in the deoxygenation unit, methane is combusted to produce carbon dioxide and water. The process sequencing makes the operation complicated.

The composition of the gas stream at the inlet of the distillation column is about 76 percent methane and 24 percent nitrogen. Thus, all or most of the oxygen as well as carbon dioxide and moisture has been removed prior to the distillation step. The decision to remove all oxygen before the distillation step was made based on earlier sensitivity simulations of the distillation column (using CHEMCAD) as a single unit. When this study was begun, it was believed that a significant degree of deoxygenation would be achieved in the distillation process itself. A CHEMCAD distillation simulation performed in order to verify this claim is shown in Figure 2. In this simulation, a feed consisting of about six percent oxygen was sent to the distillation column. When the distillation conditions were adjusted to produce about 95 percent methane in the product stream, the oxygen content of this gas was still 3.3 percent. It should be noted that nitrogen rejection of 93 percent was achieved in this separation while an oxygen rejection of only 55 percent was achieved. Furthermore, the methane concentration changes from about 72 percent at the inlet of the distillation column to about 11 percent at the outlet. Thus, within the distillation column the gas composition does reach the flammability limit, if oxygen is not removed up front. The amine unit for the removal of carbon dioxide from the gas also needs to precede the cryogenic distillation unit since even small concentrations of carbon dioxide would produce solidification in the cold-box heat exchanger, the J-T valve or the distillation tower. It would not be possible to process a gas stream containing 3.3 percent oxygen in the amine unit. This means that the deoxygenation unit must precede the amine unit, which in turn precedes the distillation tower.

Inlet oxygen concentration to the catalytic deoxygenation unit is limited to 1.5 percent in order to avoid high temperatures in the deoxygenation unit. In order to maintain the feed oxygen concentration at or below 1.5 percent, a recycle scheme was developed. In the integrated cryogenic process, the inlet flow rate to the deoxygenation unit is almost 3.5 times the feed flow rate. This means that a facility processing 3 mmscfd of feed gas with the specified composition would require a deoxygenation unit capable of processing about 10 mmscfd.

It should be noted that the waste gas stream contains about 12 percent methane when the methane concentration in the feed is 70 percent and about 30 percent methane when the methane feed concentration is 85 percent. Thus, flammability will not be a concern at higher inlet concentrations. It would also be possible to create an optimized, energy efficient process if the waste gas stream is used as fuel. This observation is found true for the other two processes as well.

The principle findings of evaluations of the integrated cryogenics process for gob gas enrichment are as follows:

- Oxygen is not removed in the same proportion as nitrogen in the distillation process. As a result, the deoxygenation unit must precede all other process operations.

- The gas recycle requirements would require processing over three times the feed gas in the deoxygenation unit. This would make the deoxygenation step expensive compared to when no recycle is required.

- The overall process appears technically feasible, but complicated. Apart from the four main process units, the process requires a number of additional heat exchangers and special process equipment.

The team performed a sensitivity study of the integrated cryogenics process. The following lists the three additional cases examined:

Flow rate	Feed methane concentration
3 mmscfd	85 percent
5 mmscfd	70 percent
5 mmscfd	85 percent

Tables 2, 3, and 4 summarize the material and enthalpy balances for these three additional cases. Comparison of the two cases (70 percent composition and 85 percent composition) at a given flow rate provide an insight as to the level of control required when there are compositional variations in the feed. It is observed that there are significant variations in duties of heat exchangers, distillation column parameters, etc. For example, the condenser duty for the distillation column changes by about 44 percent when methane concentration changes from 70 percent to 85 percent in the feed. The heat exchanger duties change by about 10 -15 percent for this compositional variation and by about 70 percent for feed flow rate change (3 mmscfd to 5 mmscfd). Thus, controlling the process with compositional and flow rate variations will be complicated. Process designers may have a few options to mitigate the effect of these variations if they are severe. These include: over-engineering various components; storing feed gas and releasing it at a steadier rate; and recycling processed gas.

Lean-oil or Selective Absorption Process

Published GRI documents (GRI, 1991; GRI 1994) and information published by Advanced Extraction Technologies (Mehra et al., 1993) formed the basis for the conceptualization of the process. The process flow sheet is shown in Figure 3. Table 5 presents the material and enthalpy balances for the base case study (3 mmscfd, 70 percent methane). The process flow diagram was constructed using CHEMCAD. The simulations used generic solvents at conditions most suitable for achieving the desired separation (determined by trial and error). The process front-end, for the removal of oxygen would be identical to the cryogenics process.

The greatest advantage of the process is that it is flexible. It is also possible to obtain high-purity product gas. Design parameters such as solvent to gas ratio and absorption column recycle permit good control of the product gas quality even when feed flow and compositions are varied. In addition, AET demonstrated the effectiveness of this technology (Mehra et al., 1993) in removing nitrogen from methane. AET may also use proprietary solvents and optimized conditions (based on their experience) to achieve better overall performance. The integrated process does require a deoxygenation unit as large as the one for the combined cryogenics method. The question of methane flammability does not arise since oxygen is removed first.

Tables 6, 7, and 8 present the material and enthalpy balances for three other cases (3 mmscfd, 85 percent methane; 5 mmscfd, 70 percent methane; and 5 mmscfd, 85 percent methane). AET demonstrated good control in their gas treatment plant in Hugoton, Kansas when enriching nitrogen contaminated natural gas. This demonstration plant has the capacity to process 5 mmscfd gas containing 13-19 percent nitrogen in the feed.

Principle findings of the evaluation of the selective adsorption approach to gas enrichment were as follows:

- It is possible to achieve a high-purity product using the lean-oil or the selective absorption approach.
- The NRU process is extremely flexible and will be able to accommodate compositional and flow variations in the feed. Adjusting other units to meet these changes may be more complicated, but is feasible.
- Since deoxygenation precedes all other process steps, a large deoxygenation unit will be required for high oxygen concentrations.

Pressure Swing Adsorption Process (PSA)

Separation of species using PSA may be governed by equilibrium or kinetic considerations. Most equilibrium-based PSA processes use wide-pore molecular sieves while narrow-pore molecular sieves (mostly zeolites) have been used for kinetic PSA separations. Most of the work for the rejection of nitrogen from methane is reported using wide-pore carbon molecular sieves, even though narrow pore zeolites have also been used to achieve the necessary separation. All of the technical evaluations in the current study were conducted for PSA processes using wide-pore molecular sieves.

Pressure swing adsorption is a dynamic process. The operation of the process depends on the breakthrough times of various gaseous components flowing through adsorption columns pressurized on a cyclic basis. It is not possible to simulate dynamic processes using conventional (steady-state) chemical engineering process simulators such as CHEMCAD. It would be possible to simulate the process using special features of ASPEN PLUS (SPEEDUP), an advanced process flow simulator. However, this exercise will require more time and is beyond the scope of the current investigation.

The cyclic PSA operation shown in Figure 4 is a five-step process consisting of pressurization, feed introduction, recycle, blowdown and purge. The following is a list of assumptions used in performing the steady-state mass balance calculations (Ruthven, et al., 1994):

- Local equilibrium between the gas and the solid phase.
- Linear, uncoupled adsorption isotherms.
- Negligible axial pressure gradients.
- Constant pressure during feed and purge steps.
- Isothermal operation.
- Single component treatment of the oxygen-nitrogen pair.

The last assumption was based on the adsorption isotherm data for carbon dioxide, methane, oxygen and nitrogen on wide-pore carbon molecular sieves at 303 K (Rodrigues, et al., 1989). The adsorption isotherms, shown in Figure 5, indicate that carbon dioxide is the most strongly adsorbed, followed by methane and that oxygen and nitrogen are only weakly adsorbed. The isotherm curves for nitrogen and oxygen fall almost on top of one another. These isotherm characteristics ensure that the separation efficiency of nitrogen and oxygen is almost identical for PSA processes employing wide-pore carbon molecular sieves.

Equations governing the material balances for each of the steps are shown in Table 9 (Ruthven et al., 1994). The table also explains the terms in these equations. The equations have been derived for a simple two-component mixture and are for two-bed operation. The recovery factors are functions of b, which in turn is a function of K_i, the Henry's Law constant for each constituent. K_i's are obtained using the adsorption data presented in Figure 5. The recovery factors are also functions of the absolute pressure ratio, which is the ratio of the highest pressure to the lowest pressure in the PSA cycle. The absolute pressure ratios for three feed compositions were calculated for the binary methane-nitrogen mixture. The calculations are tabulated in Table 10 and the recoveries are plotted in Figure 6. Table 10 and Figure 6 show that for an *ideal* PSA process, it is possible to achieve high recoveries using different pressure ratios. The pressure ratio increases from 37 to 43 as the methane concentration in the gas were to fluctuate from 92 percent to 72 percent. It should be noted that the recovery calculations are for a two-component mixture undergoing PSA separation in a two-bed system. When nonidealities and multiple components are considered, the PSA recoveries may not be as high as shown in Figure 6. However, for lack of better data, the recoveries calculated using the above described approach were incorporated in constructing integrated PSA flow charts.

Figure 7 presents the integrated PSA flow sheet. Table 11 shows the base case material and enthalpy balances. Since oxygen is rejected along with nitrogen in PSA, it is only logical to place the nitrogen rejection unit first. The PSA-NRU outlet stream contains only 0.72 percent oxygen which is removed in the deoxygenator without the necessity of recycle. It should be noted that for the base case (70 percent methane), the PSA reject stream contains about 17 percent methane. With higher methane recoveries (95 percent), the waste gas methane concentration will dip below 15 percent, the upper flammability limit for methane. Hence, for PSA processes designed for high methane recoveries, gas flammability will be a concern and will have to be addressed appropriately. For better quality feeds (> 80 percent methane), methane flammability will not be of concern. The integrated process is moderately complex with a series of heat exchangers and compressors coupled to the main process units.

Material and energy balance tables for the other three cases are shown in Tables 12, 13 and 14. Since most of the oxygen removal is also accomplished within the PSA unit, control required to account for compositional variations almost entirely rests in the PSA process. The natural gas industry considers PSA to be a flexible process amenable to good and effective control. This needs to be demonstrated, however, in the context of gob gas enrichment.

Principal findings for integrated gas clean-up using PSA include:

- For ideal, two-bed PSA operation, it is possible to achieve the desired separation between methane and nitrogen. Non-ideal, multiple-bed processes could have recoveries far lower than ideal.

- Nitrogen and oxygen are separated in the same proportion. Therefore, PSA-NRU units will effect a significant level of deoxygenation, making the final oxygen removal step simpler. However, when PSA units are designed for high methane recoveries (>95 percent), methane flammability will be of concern and will have to be addressed.

- PSA is a flexible process. The pressure ratios and cycle times could be altered to meet compositional and flow rate changes.

Summary

1. The material and energy balances performed as part of this investigation have provided a basis for assessing conversion technologies and for the evaluation of emerging processes (such as fuel cells, bioreactors, etc.).

2. Controlling any of the three integrated processes is going to be a significant technical challenge in the wake of feed compositional and flow rate variations. In order to maintain strict specifications for the product gas, it may be necessary to mix the feed gas with a higher-quality gas to keep the composition and feed within a permissible narrow range. Because of these considerations, a pilot-scale demonstration of the integrated process is advisable prior to field-scale implementation.

3. It may be possible to use the waste gas as fuel to create more energy efficient process schemes (particularly, when feed gas quality is high).

4. In the cryogenics separation process, oxygen is not removed in the same proportion as nitrogen. This makes recycle necessary for deoxygenation. Technical considerations require the deoxygenation unit to precede all other process units. It is necessary to design the deoxygenation unit to process 3.5 times more gas than the feed gas stream, when the oxygen concentration in the inlet is about five percent.

5. The selective absorption process also requires deoxygenation as the first step. It is possible to achieve high-purity product in the NRU-step of this process with considerable flexibility.

6. PSA also offers a high degree of flexibility and under ideal conditions, the necessary recovery during nitrogen rejection. Oxygen and nitrogen are separated together and makes recycle (during deoxygenation) unnecessary for the PSA integrated approach until oxygen concentrations exceed 10 percent.

7. If PSA processes are designed for high methane recoveries (>95 percent), when methane feed gas concentrations are low (<70 percent), flammable mixtures will exist within the PSA-NRU units. This concern will have to be appropriately addressed when considering high-recovery PSA units.

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Rodrigues, A. E. et al. (Eds), 1989: Adsorption, Science and Technology, Kluwer Academic Publishers, 269-283.

Ruthven, D. M. et al., 1994: Pressure Swing Adsorption, VCH Publishers, Inc., 95-164.

Note: Additional figures can be obtained by calling CMOP

APPENDIX F -

INFORMATION ABOUT THE

FOR MORE INFORMATION…

For more information on coalbed methane recovery experiences, project potential, a full listing of reports, or program activities and accomplishments, contact:

Coalbed Methane Program Manager
U.S. Environmental Protection Agency
Atmospheric Pollution Prevention Division
401 M Street, SW (6202-J)
Washington, DC 20460

Program Hotline: 1-888-STAR-YES
Facsimile: 202 565-2077
Internet: fernandez.roger@epamail.epa.gov
schultz.karl@epamail.epa.gov
Homepage: http://www.epa.gov/outreach/

Selected list of EPA Coalbed Methane Outreach Reports:

- *USEPA (U.S. Environmental Protection Agency).* To Be Released: ***Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines.*** *Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-94-012. December 1997.*

- *USEPA.* ***Proceedings: Finance Opportunities for Coalbed Methane Projects.*** *Pittsburgh Airport Marriott Hotel, Pennsylvania, April 16-17, 1996. Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-96-013.*

- *USEPA.* ***Finance Opportunities for Coal Mine Methane Projects: A Guide to Federal Assistance.*** *Public Review Draft. Office of Air and Radiation (6202J). Washington D.C. EPA 430-R-95-014. March 1996.*

- *USEPA.* ***Finance Opportunities for Coal Mine Methane Projects: A Guide for West Virginia.*** *Public Review Draft. Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-95-013. October 1995.*

- *USEPA.* ***Finance Opportunities for Coal Mine Methane Projects: A Guide for Southwestern Pennsylvania.*** *Public Review Draft. Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-95-008. June 1995.*

- *USEPA.* ***Economic Assessment of the Potential for Profitable Use of Coal Mine Methane: Case Studies of Three Hypothetical U.S. Mines.*** *Public Review Draft. Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-95-006. May 1995.*

FOR MORE INFORMATION, continued…

- *USEPA.* ***The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region.*** *Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-94-007. April 1994.*

- *USEPA.* ***Opportunities to Reduce Anthropogenic Methane Emissions in the United States. Report to Congress.*** *Office of Air and Radiation (6202J). Washington, D.C. EPA-430-R-93-012. October 1993.*

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